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2.1 INTRODUCTION AND PROJECT OVERVIEW

Hydrogen Energy International LLC (HEI) is proposing an Integrated Gasification Combined Cycle (IGCC) project called Hydrogen Energy California (HECA or Project). The facility will gasify 100 percent petroleum coke (petcoke) (or blends of petcoke and coal, as needed) to produce hydrogen to fuel a combustion turbine operating in combined cycle mode. HEI is jointly owned by BP Alternative Energy North America Inc. and Rio Tinto Hydrogen Energy LLC. The Project will produce low-carbon baseload electricity by capturing carbon dioxide (CO_2) and transporting it for CO_2 enhanced oil recovery (EOR) and sequestration (storage)[1]. The facility will be located near the Elk Hills Field and the unincorporated community of Tupman in western Kern County, California, as shown on Figure 2-1, Project Vicinity.

Highlights of the Project are as follows:

- The Project is designed to operate with 100 percent petcoke from California refineries, and has the flexibility to operate with up to 75 percent thermal input (higher heating value [HHV] basis) western bituminous coal.
- The feedstock will be gasified to produce a synthesis gas (syngas) that will be processed and purified to produce a hydrogen-rich gas, which will be used to fuel the combustion turbine for electric power generation. A portion of the product (hydrogen-rich fuel) will also be used to supplementally fire the heat recovery steam generator (HRSG) that produces steam from the combustion turbine exhaust heat.
- At least 90 percent of the carbon in the raw syngas will be captured in a high-purity carbon dioxide stream during steady-state operation, compressed, and transported by pipeline to the custody transfer point for injection into deep underground hydrocarbon reservoirs for CO_2 EOR and Sequestration.
- The power produced by the Project will have a low-carbon emission profile significantly lower than would otherwise be produced by traditional fossil-fueled sources, including natural gas.
- Project greenhouse gas emissions (e.g., carbon dioxide) and sulfur emissions will be reduced through CO_2 EOR and Sequestration and state-of-the-art emission-control technology.
- The Gasification Block feeds a 390-gross-megawatt (MW) combined cycle plant. The net electrical generation output from the Project will provide approximately 250 MW of low-carbon baseload power to the grid, feeding major load sources to the north and to the south.

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[1] This carbon dioxide will be compressed and transported via pipeline to the custody transfer point at the adjacent Elk Hills Field, where it will be injected. The CO_2 EOR process involves the injection and reinjection of carbon dioxide to reduce the viscosity and enhance other properties of the trapped oil, thus allowing it to flow through the reservoir and improve extraction. During the process, the injected carbon dioxide becomes sequestered in a secure geologic formation. This process is referred to herein as CO_2 EOR and Sequestration.

- The water source for the Project will be brackish groundwater supplied by the Buena Vista Water Storage District (BVWSD), which would be treated on site to meet Project standards. Potable water will be supplied by West Kern Water District (WKWD) for drinking and sanitary purposes.

- There will be no direct surface water discharge of industrial wastewater or storm water. Process wastewater will be treated on site and recycled within the gasification and power plant systems. Other wastewaters from cooling tower blowdown and the water treatment plant will be collected and directed to one of two on-site plant wastewater Zero Liquid Discharge (ZLD) units.

- The Project is designed with state-of-the-art emission-control technology. The Project will feature near zero sulfur emissions during steady-state operation. The Project is also designed to avoid flaring during steady-state operation, and to minimize flaring and sulfur emissions during startup and shutdown operations.

This Project Description of this Revised Application for Certification (Revised AFC)[2] describes the Project information summarized above in detail. A computer rendering of the Project is shown on Figure 2-2, Project Rendering Looking Northwest. A simplified block flow diagram of the Project is shown in Figure 2-3, Overall Block Flow Diagram.

2.1.1 Project Benefits

The Project will provide numerous benefits at the local, statewide, regional, national and global levels. Among these benefits are the following:

1. ***Helping to Ensure Adequate Supplies of Electricity***

   The Project will provide approximately 250 MW of new, baseload low-carbon generating capacity, enough to power over 150,000 homes. The California Energy Commission (CEC) estimates that the state will need to add over 9,000 MW of capacity between 2008 and 2018 to meet demand (CEC 2007). In addition, the Project will provide approximately 100 MW of natural gas generated peaking power.

2. ***Protecting the Environment***

   The Project will prevent the release of more than 2 million tons (roughly equivalent to the carbon dioxide output of 500,000 automobiles) per year of greenhouse gases to the atmosphere by sequestering them underground. The Project will employ state-of-the-art emission control technology to achieve near zero sulfur emissions and avoid flaring during steady-state operations. The Project will conserve fresh water sources by using brackish groundwater for Project process water needs. Direct surface water discharge of industrial wastewater will be eliminated through the use of ZLD technology.

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[2] HEI submitted an AFC (08-AFC-8) to the California Energy Commission on July 30, 2008, which proposed the Project on a different site. HEI subsequently decided to move the Project when it discovered the existence of previously undisclosed sensitive biological resources at the prior site. HEI respectfully submits this Revised AFC for the new Project Site which supersedes and replaces the July 30, 2008 AFC in its entirety.

3. ***Protecting Domestic Energy Supplies***

   The Project will conserve domestic energy supplies, thereby enhancing energy security. The Project will advance technology to reduce stress on U.S. natural gas supplies by using a by-product from the oil refining process and coal to generate electricity. In addition, the Project will produce additional energy from existing California oil fields by injecting carbon dioxide and increasing production by an estimated 10 to 20 percent.

4. ***Promoting Hydrogen Infrastructure***

   The Project will increase the supply of hydrogen available to support the state's goal of energy independence as expressed in California Executive Order S-7-04, which mandates the development of a hydrogen infrastructure and transportation in California. The Project is poised to supplement the quantities of hydrogen necessary for these future energy and transportation technologies and support California's role as a world leader in clean energy.

5. ***Stimulating the Local and California Economy***

   The Project will boost the local and California economy with an estimated 1,500 jobs associated with construction and 100 permanent positions associated with Project operations.

2.1.2 Project Objectives

Project objectives are summarized as follows:

- Provide an efficient, reliable, and environmentally sound low-carbon power generating facility to help meet future electrical power needs.
- Mitigate impacts related to climate change by dramatically reducing average annual greenhouse gas (GHG) emissions relative to the GHG emitted from a conventional power plant by capturing and sequestering carbon dioxide emissions.
- Minimize environmental impacts associated with the construction and operation of the Project through choice of technology, project design and implementation of feasible mitigation measures if necessary
- Facilitate and support the development of hydrogen infrastructure in California by supplementing the quantities of hydrogen available for future energy and transportation technologies.
- Conserve domestic energy supplies and enhance energy security by using a by-product from the oil refining process to generate electricity, and enhancing production of domestic petroleum reserves.
- Site the Project at a location over which HEI is reasonably likely to obtain control, and which offers reasonable access to necessary infrastructure, including natural gas and non-potable

water supply, transmission interconnection, and geologic formations appropriate for CO_2 EOR and Sequestration.

- Ensure the economic viability of the Project by minimizing costs while achieving other Project objectives.

2.1.3 Project Ownership

HEI is jointly owned by BP Alternative Energy North America Inc. and Rio Tinto Hydrogen Energy LLC, with the prime objective of producing hydrogen for low-carbon power generation. HEI proposes to be the owner and operator of the IGCC facilities and has the option to purchase the 473-acre Project Site, as defined below, from the site owner. HEI also has the option to purchase 628 acres surrounding the Project Site, herein referred to as Controlled Area, in which HEI will control access and future land uses.

The transmission line will be owned by HEI up to the point of interconnect (Midway Substation) as stipulated by the California Independent System Operator (CAISO). HEI will own the carbon dioxide pipeline up to the custody transfer point. Natural gas supply lines will be owned by Pacific Gas and Electric (PG&E) or Southern California Gas Company. The process water supply line will be owned by Buena Vista Water District. The potable water supply line will be owned by WKWD.

2.1.4 Schedule

The milestones for the Project are anticipated to be as follows:

Completion of CEC permitting process	May 2011
Start of construction	December 2011
Completion of construction	December 2014
Commissioning and initial startup	October 2014 through August 2015
Commercial operation of the Project	September 2015

2.1.5 Location

The Project Site consists of approximately 473 acres located near a hydrocarbon-producing area in Kern County, California, as shown in Figure 2-1, Project Vicinity. The Project Site is located in a predominantly agricultural area of the county, 1.5 miles northwest of the unincorporated community of Tupman. The 473-acre Project Site is located within Section 10 of Township 30 South, Range 24 East in Kern County. The Project Site Assessor's Parcel Numbers (APN) are as follows:

- Part of 159-040-16
- Part of 159-040-18

The Controlled Area is shown on Figure 2-4, Site Plan. The APNs associated with the Controlled Area are as follows:

- 159-040-02
- 159-040-04
- 159-040-11
- Remnant part of 159-040-16
- Remnant part of 159-040-18
- 159-190-09

The Project Site is predominantly used for agricultural purposes, including cultivation of cotton, alfalfa and onions. The Project Site vicinity consists primarily of agricultural uses. Adjacent land uses include Adohr Road and agricultural uses to the north; Tupman Road and agricultural uses to the east, agricultural uses and an irrigation canal to the south; and a residence, structures (used for grain storage and organic fertilizer production), agricultural uses, and Dairy Road right of way to the west. The West Side/Outlet Canal, Kern River Flood Control Channel, and the California Aqueduct (State Water Project) are approximately 500, 700, and 1,900 feet south of the Project Site, respectively.

2.1.6 Affected Project Study Areas

The Project Site and linear facilities comprise the affected study area and are entirely located in Kern County, California. These Project components are described below.

Major on-site Project components will include, as shown on Figure 2-5, Preliminary Plot Plan:

- Solids Handling, Gasification, and Gas Treatment
  - Feedstock delivery, handling and storage
  - Gasification
  - Sour shift/gas cooling
  - Mercury removal
  - Acid gas removal

- Power Generation
  - Combined cycle power generation
  - Auxiliary combustion turbine generator
  - Electrical switching facilities

- Supporting Process Systems
  - Natural gas fuel systems
  - Air separation unit (ASU)
  - Sulfur recovery unit (SRU)/Tail Gas Treating Unit (TGTU)
  - ZLD units for process and plant waste water streams
  - Carbon dioxide compression
  - Water treatment plant
  - Other plant systems

The Project also includes the following off-site facilities, as shown on Figure 2-7, Project Location Map. These offsite linears are summarized below and described in more detail in Section 2.6.1.10, Linear Construction.

- **Electrical Transmission Line** – An electrical transmission line will interconnect the Project to PG&E's Midway Substation. Two alternative transmission line routes are proposed; each alternative is approximately 8 miles in length.

- **Natural Gas Supply Pipeline** – A natural gas interconnection will be made with PG&E or SoCalGas natural gas pipelines, each of which is located southeast of the Project Site. The natural gas pipeline will be approximately 8 miles in length.

- **Water Supply Pipelines** – The Project will utilize brackish groundwater supplied from the BVWSD located to the northwest. The raw water supply pipeline will be approximately 15 miles in length. Potable water for drinking and sanitary use will be supplied by WKWD to the southeast. The potable water supply pipeline will be approximately 7 miles in length.

- **Carbon Dioxide Pipeline** – The carbon dioxide pipeline will transfer the carbon dioxide captured during gasification from the Project Site southwest to the custody transfer point. Two alternative carbon dioxide pipeline routes are proposed; each alternative is approximately 4 miles in length.

The Project components described above are shown on Figure 2-8, Project Location Details, which depicts the region, the vicinity, and Project Site and its immediate surroundings.

All temporary construction equipment laydown and parking, including construction parking, offices, and construction laydown areas, will be located within the Project Site.

The disturbed acreage associated with the Project is summarized in Table 2-1, Project Disturbed Acreage.

Table 2-2, Site Characteristics, summarizes site meteorology and other characteristics upon which the Project design has been based.

2.1.7 Site Plan and Access

Figure 2-5, Preliminary Plot Plan, presents a scaled, overall plot plan for the Project. The Preliminary Plot Plan also identifies the primary site access, which will be from Adohr Road on the northern side of the Project Site. Elevations are shown on Figure 2-6, Project Elevations.

Table 2-3, Project Linear Tie-in Location on Plot Plan, provides a list of the currently anticipated Project pipelines, communication, and electrical interfaces at the site boundaries.

Table 2-1
Project Disturbed Acreage

Project Component	Size	Approx. Linear Length (miles)	ROW Construction	ROW Permanent	Temporary Disturbance (acres)	Permanent Disturbance (acres)
Project Site	473 acres	NA	NA	NA	473	250
Electrical transmission line	25-foot-diameter structural base (60 structures total)	8	175 feet[1]	150 feet	24	0.67[2]
Natural gas pipeline	16-inch diameter	8	50 feet	25 feet	50[3]	0.33[4]
Process water pipeline	20-inch diameter	15	50 feet	25 feet	93[5]	0.29[6]
Potable water pipeline	6-inch diameter	7	Accounted for in Natural Gas Line ROW	Accounted for in Natural Gas Line ROW	Accounted for in Natural Gas Line ROW	Accounted for in Natural Gas Line ROW
CO_2 pipeline	12-inch diameter	4	50 feet	25 feet	25[3]	0.11[7]
Temporary Construction Areas	Accounted for in Project Site	NA	NA	NA	Accounted for in Project Site	None
Total Project Disturbance					**665**	**251.4**

Source: HECA Project

Notes:
~ = approximately
CO_2 = carbon dioxide
NA = not applicable
ROW = right of way

1. This is a maximum width required in areas where structures will be installed. However, total temporary disturbance along the entire route is calculated based on the following: (1) a 150-foot by 150-foot area is required for each of the 60 structures, equaling 31 acres; and (2) 25-foot temporary roadway is required along the entire 8-mile line, equaling 24 acres.
2. Consists of permanent ground disturbance associated with the base of the 60 new structures.
3. Acreage includes the area required for the entry/exist pits.
4. Acreage includes permanent disturbance occupied by the gas metering station located within the Controlled Area southeast of the Project Site.
5. Acreage includes the 100-foot by 150-foot temporarily disturbed area required for the construction of each of five groundwater wells.
6. Acreage includes the 50-foot by 50-foot permanent disturbed area required for each of five groundwater wells.
7. Acreage includes two 50-foot by 50-foot valve boxes positioned along the pipeline route.

Table 2-2
Site Characteristics

Elevation	**General site elevation varies slightly from the high point grade elevation of 291 feet above mean sea level (msl).**	
Design Ambient Temperature and Humidity	**Dry Bulb (Fahrenheit)**	**Relative Humidity (%)**
Average Ambient	65°	55
Summer Design	97°	20
Winter	39°	82
Extreme Minimum Ambient	20°	85
Extreme Maximum Ambient	115°	15
Design Ambient Barometric Pressure		14.54 psia
Rainfall		
Average Precipitation per year		5.7 inches (average. 2000 – 2006)
24-hour Max Precipitation (50-year storm)		1.8 inches
Prevailing Wind Direction & Average Speed		Wind Rose

Source: Computed from Annual and Monthly Summaries (year span) of Bakersfield, California Meteorological Data, NOAA, National Climate Data Center, Asheville, North Carolina.

Notes:
The 25-year, 24-hour maximum precipitation is 1.8 inches
ºF = degrees Fahrenheit
% = percent
msl = mean sea level
psia = pounds per square inch absolute

Table 2-3
Project Linear Tie-in Location on Plot Plan

Interface Description	Tie-In Location
Communications Conduit	Within other linear facility easements
Water Supply	South side of Plot
Potable Water Supply	Southeast side of Plot
Plant Wastewater Discharge	None (ZLDs)
Natural Gas Supply	Southeast side of Plot
Carbon Dioxide Export	Southwest side of Plot
Transmission Line	West side of Plot

Source: HECA Project

2.1.8 Resource Inputs

Unlike most power plants in California, this Project uses domestic supplies of solid feedstock. The feedstocks for the Project include the following and are discussed below in more detail:

- Petcoke and western bituminous coal
- Fluxant (crushed aggregate, rock, or sand)
- Natural Gas
- Water
- Oxygen
- Nitrogen

2.1.8.1 Petcoke and Western Bituminous Coal

The primary feedstock for the gasification plant is petcoke. Petcoke will be supplied from refineries in the Los Angeles, Bakersfield, or other northern California areas, and/or other regional sources. The petcoke that will be used for the Project is a by-product from the oil refining process which is predominantly exported overseas for use as a low-grade fuel. Western bituminous coal may also be blended, up to 75 percent (thermal input HHV basis), with petcoke to diversify the feedstock supply. Furthermore, in order to qualify for federal funding initiatives, minimum coal feedstock requirements may be mandated for limited durations. Transportation of petcoke and coal to the Project will be by truck. Coal will be brought in-state by rail and trans-loaded onto trucks at a nearby transloading terminal.

Feedstock storage will include 15,000 tons of active storage (sufficient for three to 5 days of operation) and at least 30 days inactive emergency storage based on the maximum plant production rate. Active storage will include three 5,000-ton entirely enclosed cone-bottom silos (with baghouses), with one or more silos dedicated for each type of feedstock (depending on plant operation). An inactive storage pile, covered with stabilizer, will be provided on site.

The truck unloading system, feedstock reclaiming and blending system, and pre-crushing system will have dust collection systems to minimize particulate emissions. The grinding mill feed bins will be totally enclosed and will include baghouses. Petcoke and coal will be transported from the truck unloading system to the active storage silos, pre-crushing system, and grinding mill feed bins in enclosed conveyors with dust collection systems.

Petcoke

Petcoke is expected to be the lowest cost feedstock available to the Project. Approximately 16,350 tons per day (tpd) (6.0 million tons per year [tpy]) of fuel grade petcoke are produced by major California refineries, including BP. Five of these refineries are located in the Los Angeles area, three are in the San Francisco area, and two are in central California. At steady-state operation feeding 100 percent petcoke, the Project would consume about 17 percent of this total production (around 2,820 tpd, or 1.0 million tpy).

Bituminous Coal

The Project expects to obtain its necessary western bituminous coal from the Uinta Basin in Utah and Colorado. Approximately 0.5 million tpy of Uinta Basin coal is delivered to a transloading facility in the Bakersfield area for use by small cogeneration facilities. Several western bituminous coal mines that can supply coal meeting Project technology requirements in terms of ash composition and other characteristics have already been identified. The Project is in the process of discussing possible contractual terms with the relevant entities.

Delivered Fuel Costs

Over the long term, delivered petcoke costs are expected to be lower than delivered coal costs, primarily as a result of transportation cost differentials. Hauling distances for petcoke are short enough to favor truck movements, and competition between trucking firms will help minimize these costs. These truck shipments can be delivered directly to the Project Site for unloading. The longer coal hauls from the Uinta Basin will require rail shipments. Railcars will be transloaded to trucks at a nearby transloading terminal for local delivery to the Project.

Feedstock Quality and Plant Operations

Feedstock Flexibility

To maximize the number of potential fuel suppliers and to minimize fuel costs, the Project is designed to accept a range of feedstock blends. It incorporates a fluxant injection system to allow operation on 100 percent petcoke, but can also operate on a blend of as much as 75 percent thermal input (HHV basis) coal, with petcoke.

Sulfur Content

The sulfur recovery system will handle feedstock blends whose average sulfur content is within the range of the different assumed feedstocks. Western bituminous coal has an average sulfur content of approximately 1.0 percent. The average sulfur content of California’s fuel grade petcoke is approximately 3.4 percent today, but is expected to climb to 4.5 percent by 2020. Petcoke from a local refinery in Bakersfield contains approximately 1.0 percent sulfur, while petcoke from one potential Los Angeles refinery averages 6.5 percent sulfur. Petcoke sulfur levels are expected to increase over time as heavier crudes are processed at a number of California refineries. The Project design range will accommodate both current and expected future sulfur levels in California petcokes. Higher sulfur petcoke generally bears a discount to lower sulfur petcoke in the marketplace, and the ability to process higher sulfur feedstocks will help to minimize fuel costs.

Transportation and Logistics

Trucking

A number of trucking firms with petcoke handling experience have been identified and have been engaged in preliminary discussions. All have expressed interest in serving the Project. The use of central California or San Francisco area petcokes would minimize truck shipments from the Los Angeles area, and the use of central California petcokes would also serve to minimize emissions and transportation costs. The trucking companies contacted have expressed an interest in considering alternative fuel vehicles to service the Project if costs are competitive with other fuels.

Rail Shipments and Transloading

Because of the distances involved, western bituminous coal procured for the Project will need to be delivered to the Bakersfield area by rail. A rail-to-truck transloading facility option is already operating in the Bakersfield area that will be available to support transportation of coal feed to the Project Site.

Storage

The Project will provide three to 5 days of storage at normal usage rates on site in three 5,000-ton completely enclosed cone-bottom silos (with baghouses): two for petcoke and one for coal. The Project will also provide approximately 30 days of total inactive emergency storage on site for petcoke or coal/petcoke blends at the Project's maximum design usage rate. As a result, the total enclosed and inactive emergency storage capacity at the Project Site equals approximately 35 days of inventory.

Feedstock Characteristics

A representative feedstock analysis is provided below for each of the feedstocks. The representative feedstock analysis for petcoke is provided in Table 2-4, Petcoke Design Range. The representative feedstock analysis for western bituminous coal is provided in Table 2-5, Typical Analysis for Western Bituminous Coal.

2.1.8.2 Fluxant

Slagging gasifiers require that the mineral matter in the feedstock melt and flow by gravity out of the bottom of the gasifier reaction chamber. When using petcoke feedstock and/or coal feedstocks containing ash that melts at high temperatures, the addition of a fluxant is required to achieve the proper molten "gasification solids" flow characteristics at acceptable gasifier operating temperatures, thus facilitating gravity flow. Both the type and quantity of fluxant required are dependent upon the feedstock characteristics.

Fluxants will be transported to the plant by truck. Fluxants will be pneumatically conveyed to the fluxant bins, which will have baghouses to control particulate emissions.

Fluxants for Petcoke Feedstocks

As part of the design process, the Project underwent an extensive petcoke fluxant evaluation to assess more than 30 fluxant candidates for environmental, operational, technical, and commercial criteria. As a result of this evaluation, three primary sources of fluxant have been selected that will meet the Project's requirements. These include common construction and industrial grade

Table 2-4
Petcoke Design Range

Ultimate Analysis, wt% (dry)	
Carbon	84 – 91
Hydrogen	3 – 5
Nitrogen	1-4
Sulfur	0.8 – 6.0
Oxygen	<1.0
Ash	0.3 – 1.0
Moisture, wt% (AR)	5 – 15
Chloride Content, ppmw (dry)	100 – 300
Gross Heating Value, Btu/lb (dry)	14,500 – 15,500
Bulk Density, lb/ft^3 (AR)	40 – 50
Ash Analysis, ppmw (dry)	
Vanadium	900 – 1,200
Nickel	700 – 1,250
Iron	500 – 1,000
Chromium	<10
Sodium	50 – 500
Calcium	50 – 500

Source: HECA Project

Notes:
% = percent
< = less than
> = greater than
AR = as received
Btu/lb = British thermal units per pound
ft^3 = cubic feet
ppmw = parts per million by weight

materials, such as crushed aggregate, rock and sand. Table 2-6, Example Fluxant Composition, presents a representative composition of one of the fluxant candidates required for the Project when operating on petcoke feedstocks.

Fluxants for Coal and Coal/Coke Blend Feedstocks with High Melting Ash

To meet the Project's operating requirements, limestone will be used as a fluxant for coals and coal/coke blends containing ash with high melting points. Locally available limestones will be evaluated during operations and will be selected based on fluxant effectiveness, type and concentrations of impurities, handling/safety/environmental considerations, and local market pricing and availability.

Table 2-5
Typical Analysis for Western Bituminous Coal

Ultimate Analysis, wt% (dry)	
Carbon	70 – 76
Hydrogen	4.4 – 6.7
Nitrogen	0.6 – 1.6
Sulfur	0.1 – 2.0
Oxygen	7.0 – 14.5
Ash	4.8 – 11.2
Moisture, wt% (AR)	5.0 – 12.0
Gross Heating Value, Btu/lb (dry)	11,300 – 13,600
Ash Analysis, ppmw (dry)	
Vanadium	8 – 9
Nickel	4 – 12
Chromium	7 – 12
Mercury	0.02 – 0.08

Source: HECA Project

Notes:
% = percent
AR = as received (with delivered free moisture)
Btu/lb = British thermal units per pound
ppmw = parts per million by weight

Table 2-6
Example Fluxant Composition

Constituent	Dry wt%
Silicon Dioxide (SiO_2)	47
Aluminum Oxide (Al_2O_3)	14
Iron Oxide (Fe_2O_3)	16
Calcium Oxide (CaO)	8
Magnesium Oxide (MgO)	4
Sodium Oxide (Na_2O)	4
Potassium Oxide (K_2O)	1
Titanium Dioxide (TiO_2)	2
Manganese Dioxide (MnO_2)	0.4
Phosphorus Pentoxide (P_2O_5)	2
Strontium Oxide (SrO)	0.1
Barium Oxide (BaO)	0.1
Sulfur Trioxide (SO_3)	0.3
Balance	1.1
Total (dry)	**100.00**
Water, wt%	0.70 (normal) – 3 (max)

Source: HECA Project
wt% = percent by weight

2.1.8.3 Natural Gas

Natural gas is required to start up the combustion turbine to the load required to accept hydrogen- rich fuel. Natural gas also serves as a backup fuel to allow electric power generation to continue when hydrogen-rich fuel is not available due to, for example, maintenance of the gasifier unit. Natural gas is also used to fuel the auxiliary combustion turbine, auxiliary boiler, flare pilots, startup of the SRU, and support fuel for the SRU tail gas thermal oxidizer. Natural gas is also used to preheat the gasifier refractory. The natural gas supply meter station will be located within the Controlled Area, southeast of the Project Site.

Two large natural gas pipelines systems (PG&E and Southern California Gas [SoCalGas]) are available to supply natural gas to the Project. The distance between the main pipeline system headers and the Project Site is approximately 8 miles.

- The estimated delivery pressure of the PG&E line is between a minimum of 335 pounds per square inch gauge (psig) and a maximum of 600 psig.

- The estimated minimum delivery pressure of the SoCalGas Company pipeline is 350 psig. Historical data from 2008 shows that the pipeline pressure was at 500 psig or higher for 95.8 percent of the time, which is sufficient for operation of the General Electric (GE) 7FB combustion turbine.

The interconnect will consist of one tap off the existing transmission line, one meter set, one service pipeline service connection, and a pressure limiting station located on the Project Site. The pipeline route is shown on Figure 2-7, Project Location Map. See project location details on Figure 2-8, Project Location Details.

The SoCalGas natural gas is proposed to be used by the Project.

Typical yearly averages for the natural gas composition and physical properties are given below in Table 2-7, Typical Natural Gas Composition.

The minimum natural gas pressure required at the General Electric (GE) 7FB combustion turbine generator (CTG) fuel supply interface is 400 psig. Because the natural gas supply pressure will be less than 400 psig for a relatively small amount of time, natural gas compression will not be required to supply fuel to the GE 7FB combustion turbine.

The minimum natural gas pressure required at the GE LMS100® auxiliary turbine fuel supply interface is 960 psig. A natural gas compressor will be required to meet the pressure requirements for this turbine.

2.1.8.4 Water

It is estimated that the Project will use about 2,900 gallons per minute (gpm) (4.2 million gallons per day [mgd]) of brackish water on an average annual basis. This increases to about 4,100 gpm (5.9 mgd) during average summer afternoon conditions. The Project will use local brackish groundwater treated on site to meet Project standards. The brackish groundwater will be

Table 2-7
Typical Natural Gas Composition

Pressure, psig (for CTG startup and as a backup fuel)	>350 psig
Specific Gravity	0.588
Higher Heating Value, Btu/scf	1,035
Composition, mol%	
Hydrogen (H_2)	0.00
Methane (CH_4 or C_1)	95.165
Ethane (C_2)	2.52
Propane (C_3)	0.58
iso-Butane (i-C_4)	0.115
normal Butane (n-C_4)	0.1
iso Pentane (i-C_5)	0.035
normal Pentane (n-C_5)	0.025
Hexanes plus higher carbon compounds (C_6+)	0.025
Carbon Monoxide (CO)	0.00
Carbon Dioxide (CO_2)	0.885
Nitrogen (N_2)	0.565
Hydrogen Sulfide (H_2S)	<1/4 grain/100 scf
Total Sulfur	<3/4 - 1 grain/100 scf

Source: Southern California Gas Company

Notes:
< = less than
> = greater than
Btu = British thermal units
CTG = combustion turbine generator
psig = pounds per square inch gauge
mol% = mole percent
scf = standard cubic feet

supplied from the BVWSD, which is a local water district with impaired groundwater sources not suitable for agricultural or potable use. BVWSD has stated that it will be able to provide brackish groundwater with an average total dissolved solids (TDS) concentration of approximately 2,000 milligrams per liter (mg/L), with an acceptable range from about 1,000 to 4,000 mg/L, to the Project for the estimated life of the Project. Potable water will be supplied by WKWD located near the State Route (SR) 119/Tupman Road intersection, southeast of the Project Site.

Water usage in the Project can be divided into five categories (power CT, gasification CT, ASU CT, HRSG stack, gasification solids). Figure 2-9, Water Usage and Figure 2-10, Water Use and Recovery System Diagram, depict the water usage allocated by category.

Most of the water usage is for heat rejection. Three of the four major areas of water usage are for heat rejection in the form of evaporation from cooling towers. Two of the three cooling towers (the Gasification cooling tower and the ASU cooling tower) are associated with the gasification process, while the other cooling tower (the Power Block cooling tower) is used by the power block, the majority of which is for condenser duty.

The HRSG stack water content is a direct result of combustion of the hydrogen-rich fuel gas. The petcoke feedstock to the Gasification Block has very little hydrogen; therefore, nearly all of the hydrogen in the fuel starts as water feed to the plant. Water is converted to hydrogen in the gasifier and in the shift reactors. In the gasifier, carbon and carbon monoxide react with water to form hydrogen, carbon monoxide, and carbon dioxide. The shift reactors convert carbon monoxide and water into hydrogen and carbon dioxide.

The plant wastewater ZLD water usage loss is very small, and therefore its value is not included in this section. Mixed power plant wastewater, including cooling tower blowdown, water treatment reject, evaporative cooler blowdown, and other miscellaneous drains is evaporated and concentrated using a conventional mechanical vapor recompression Brine Concentrator followed by a Brine Crystallizer.

2.1.8.5 Oxygen and Nitrogen

The gasification process requires high-pressure, high-purity oxygen (95 volume percent). The oxygen is supplied from the ASU, which separates and purifies oxygen and nitrogen from the ambient air. The ambient air is filtered, compressed, dried, and cooled to cryogenic temperatures. The resultant oxygen is sent to the gasifier as one of the feeds. The ASU also supplies oxygen to the SRU.

The ASU supplies compressed nitrogen to the combustion turbine. The nitrogen is used as a diluent that reduces thermal nitrogen oxide (NO_x) produced when hydrogen-rich gas is combusted. The ASU also provides high-purity nitrogen for purging equipment, piping, and instrumentation.

2.1.9 Product Output

Unlike a typical power plant, an IGCC produces several products in addition to electricity, including the following, which are discussed below in more detail:

- Carbon dioxide
- Molten sulfur
- Gasification solids

2.1.9.1 Electricity and Transmission Line

An electrical transmission line will interconnect the Project Site to PG&E Midway Substation. The interconnection voltage is expected to be 230 kilovolts (kV), to be verified by California Independent System Operator (CAISO). Four alternative routes were initially considered (as discussed in Section 4, Electrical Transmission), and two were eliminated, leaving two routes for further detailed evaluation in this Revised AFC. Each extends from the Project Site in a predominantly northwest direction and enters the substation on its north side. PG&E has proposed constructing two new 230-kV bays on the north side of the substation. Each potential route is approximately 8 miles in length. While a preferred alternative has not been selected, the decision criteria for selecting the preferred route will include: environmental impact; engineering design and construction considerations; land availability; transmission loss; and future operation and maintenance requirements.

Table 2-8, Electrical Specification, describes the general specifications for electricity delivery.

Table 2-8
Electrical Specifications

Terminal Point	230-kV Plant Switchyard
Utility Interconnection Location	PG&E Midway 230-kV Substation
Line Voltage	230 kV
Frequency	60 Hz
Switchyard	Outdoor Switchyard

Source: HECA Project

Notes:
Hz = Hertz
kV = kilovolts
PG&E = Pacific Gas and Electric Company

Figure 2-11 presents the one-line diagram for the existing PG&E Midway Substation after the interconnection of the Project.

The conductor selected for the preliminary design is a 1,158 kcmil aluminum conductor steel supported conductor with trapezoidal stranding (ACSS/TW) for the aluminum strands. The code name for this conductor is Genesee/ACSS/TW.

2.1.9.2 Carbon Dioxide

Carbon dioxide will be compressed and transported by pipeline to a custody transfer point in the Elk Hills Field for CO_2 EOR and Sequestration. Two possible custody transfer points and associated pipeline routes are being evaluated in this Revised AFC. Each route extends predominantly southwest to the respective custody transfer point and parallels existing private roads. The potential routes are approximately 4 miles in length. The preferred custody transfer point will be determined by Occidental of Elk Hills, Inc. (Oxy Elk Hills). Only one pipeline route will be developed, based on the determined custody transfer point. Section 8 and Appendix F of this Revised AFC discuss CO_2 EOR and sequestration.

2.1.9.3 Molten Sulfur

As part of the gasification process, the Project will produce molten sulfur, which will be sold and transported by truck off site for agricultural and other uses. An average of five trucks of sulfur per day will be transported from the Project Site. Table 2-9, Sulfur Specifications, describes the sulfur specification.

Table 2-9
Sulfur Specifications

Maximum Quantity	180 stpd
Quality	Commercial Grade Degassed Liquid Sulfur
Degassed H_2S Content	<10 ppmw

Source: HECA Project

Notes:
< = less than
H_2S = hydrogen sulfide
ppmw = parts per million by weight
stpd = short tons per day

2.1.9.4 Gasification Solids

The estimated production of gasification solids is estimated to average 140 stpd (wet) on a plant feedstock of 100 percent petcoke and is estimated to average 470 stpd (wet) on a plant feedstock of 75 percent coal/25 percent petcoke (thermal input HHV basis). The maximum gasification solids production rate is estimated to be 750 stpd (wet). The wide range of production estimates is due to the variability of the feed ratios and the resulting variation in the unreacted carbon content of the solids. The overall average number of daily truckloads departing the site (accounting for the anticipated variation in feedstocks) is 11. The maximum number of daily truckloads is anticipated to be 38.

The exact composition of the gasification solids cannot be determined until the Project is in operation and typical gasification solids are generated. However, the composition can be projected, based on feed materials. Other operating solid feed gasification plants generate gasification solids for beneficial uses. These plants are generally similar to the Project, with respect to gasification equipment, process specifications, and feed material blends. For this reason, Table 2-10, Example Composition Range of Gasification Solids, presents a typical range of compositions for the gasification solids. Options for potential uses of the gasifier solids are being evaluated by the Project and include applications in the cement industry, aggregate or road base industry, metal recovery (for vanadium and nickel recovery), and/or blending with petcoke to form a saleable solid fuel.

2.1.9.5 Wastewater Discharge

The Project has been designed for ZLD and therefore will not discharge surface water or wastewater off site. Wastewater produced internally will be fully recycled and reused. Project wastewater will primarily result from cooling tower blowdown, water supply treatment, and

Table 2-10
Example Composition Range of Gasification Solids

Compound	Projected Weight %, Wet		
	Minimum	Average	Maximum
Vanadium Pentoxide (V_2O_5)	0.16	1.23	2.68
Nickel Sulfide (NiS)	0.03	0.09	0.23
Nickel (III) Oxide (Ni_2O_3)	0.00	0.80	1.86
Iron (II) Sulfide (FeS)	0.02	1.22	4.59
Iron (III) Oxide (Fe_2O_3)	0.00	3.65	7.46
Chromium (III) Oxide (Cr_2O_3)	0.00	0.02	0.05
Sodium Oxide (Na_2O)	0.54	1.21	2.00
Calcium Oxide (CaO)	1.61	2.69	3.71
Mercury (Hg)	0.00	0.00	0.00
Silicon Dioxide (SiO_2)	8.97	15.70	21.46
Aluminum Oxide (Al_2O_3)	2.59	6.26	12.82
Magnesium Oxide (MgO)	0.35	1.00	1.75
Potassium Oxide (K_2O)	0.15	0.32	0.51
Titanium Dioxide (TiO_2)	0.23	0.55	0.93
Manganese Dioxide (MnO_2)	0.00	0.07	0.14
Phosphorus Pentoxide (P_2O_5)	0.20	0.53	0.91
Strontium Oxide (SrO)	0.00	0.03	0.05
Barium Oxide (BaO)	0.00	0.02	0.05
Sulfur Trioxide (SO_3)	0.00	0.00	0.00
Unknowns	0.11	0.50	1.42
Water (H_2O)	49.84	52.57	57.93
Carbon (C)	1.42	11.54	25.99

Source: HECA Project

Note:
% = percent

gasification process condensate blowdown. The cooling tower circulation water and the process condensate from gasification will be recycled to the maximum practical extent. Cooling tower blowdown that cannot be recycled and reject water from the water treatment plant will be sent to a plant wastewater zero liquid discharge (ZLD) unit. Gasification blowdown that cannot be recycled will be sent to a separate process wastewater ZLD unit. Each of these waste streams will be treated and recovered as high purity water and a ZLD solids. Any contaminants in the gasification blowdown water will be concentrated in the ZLD solids and will not be allowed to mix with the cooling tower blowdown/water supply treatment reject ZLD solids to avoid unnecessary contamination. The solids from the process wastewater ZLD unit comprise a relatively small quantity that may be determined to be a hazardous waste and will be tested and disposed of at an offsite disposal facility in accordance with applicable laws, ordinances, regulations and standards (LORS). The recovered water will be reused within the plant. The ZLD solids from the plant wastewater ZLD unit is almost entirely composed of the minerals concentrated from the plant's water supply. The ZLD solids from the plant wastewater ZLD is a larger quantity and is not expected to be determined to be a hazardous waste. The recovered water will be reused within the plant and the ZLD solids will be tested and disposed of in accordance with applicable LORS.

Sanitary wastewater from the Project restrooms, showers, and kitchens will be conveyed by an underground gravity collection system and discharged to a private on-site sewage disposal system consisting of a conventional septic tank and leach field**.** No municipal system is available in the immediate area to serve the Project.

2.1.10 Plant Performance Summary

The following tables provide representative Project performance information. Table 2-11, Representative Heat and Material Balances, presents heat and material balances for the various operating configurations and ambient conditions. Table 2-12, Maximum Feeds and Products, shows the maximum feed and product rates anticipated for the Project.

2.2 SOLIDS HANDLING, GASIFICATION, AND GAS TREATMENT

2.2.1 Overview of Gasification Technology

Gasification typically involves two distinct processes: pyrolysis and gasification. In practice, the processes may either occur in two different reactors or be combined in one reactor. Pyrolysis and gasification are defined as follows:

- **Pyrolysis** – The thermal degradation of carbon-based materials through the use of an indirect, external source of heat, typically at temperatures of 750 degrees Fahrenheit (°F) to 1,650°F, in the absence or almost complete absence of free oxygen (O_2). This thermally decomposes and drives off the volatile portions of the organic materials, generating syngas composed primarily of hydrogen (H_2), carbon monoxide (CO), carbon dioxide (CO_2), and methane (CH_4).

- **Gasification** – The thermal conversion of carbon-based materials in the presence of internally produced heat, typically at temperatures of 1,400°F to 3,000°F, and in a limited supply of air/oxygen (less than stoichiometric, or less than is needed for complete combustion) to produce syngas, composed primarily of hydrogen and carbon monoxide.

The Project uses GE's quench gasification technology. The GE quench gasifier feeds petcoke (or coal/petcoke blends) as a water slurry along with oxygen into a refractory-lined reactor vessel. The gasifier operates between 2,400°F and 2,700°F. Part of the feed to the gasifier is initially oxidized very rapidly, providing the necessary heat for the gasification reactions. The feed to the gasifier passes through the pyrolysis temperature region very rapidly (in a few thousandths of a second) and the gasification reactions determine the gasifier chemistry and performance.

Table 2-11
Representative Heat and Material Balances

Operating Case:	IGCC PG7321 (FB) Hydrogen-Rich Gas from: 100% Petcoke	75 % Coal/25 % Petcoke Blend [3]	Combined Cycle PG7321 (FB) Natural Gas			Auxiliary CTG LMS100® Natural Gas		
Ambient Temperature, °F	65 [1]	65 [1]	20	65	115	20	65	115
Feeds:								
Feedstock, stpd (AR)	2,820	3,197	0	0	0	0	0	0
Feedstock, MMBtu/hr [HHV]	3,240	3,255	0	0	0	0	0	0
Fluxant, stpd	60	32	0	0	0	0	0	0
Natural Gas, MMBtu/hr [HHV]	0	0	2,560	2,410	2,310	880	910	860
Water, gpm	2,900	2,810	1,080	1,450	2,130	160	240	390
Products and By-Products:								
Hydrogen, mmscfd [2]	177	177	0	0	0	0	0	0
Carbon Dioxide, stpd	7,400	7,300	0	0	0	0	0	0
Sulfur, stpd	130	40	0	0	0	0	0	0
Gasification Solids, stpd (wet)	140	470	0	0	0	0	0	0
Power Balance:								
Combustion Turbine, MW	232	232	201	183	169	101	103	96
Steam Turbine, MW	160	156	148	146	142	0	0	0
H_2-Rich Fuel Expander, MW	2	2	0	0	0	0	0	0
Gross Power, MW	394	390	349	329	311	101	103	96
Total Auxiliary Load, MW	143	142	16	18	18	3	3	4
Air Separation Unit, MW	74	75	0	0	0	0	0	0
CO_2 Compression, MW	27	27	0	0	0	0	0	0
Other Internal Users, MW	42	40	16	18	18	3	3	4
Net Power, MW	251	248	333	311	293	98	100	92

Source: HECA Project

Notes:
[1] Ambient temperature variations have minimal effect on hydrogen-rich gas fueled combustion turbine generator output and gasification operation. Results are nearly constant for plant output across the ambient temperature range.
[2] Hydrogen contained in the hydrogen-rich gas used to fuel power generation equipment.
[3] Percentage is by thermal input (HHV basis)

AR = as received
CTG = combustion turbine generator
°F = degrees Fahrenheit
gpm = gallons per minute
HHV = higher heating value
IGCC = integrated gasification combined cycle
MMBtu/hr = million British thermal units per hour
mmscfd = million standard cubic feet per day
MW = megawatt
stpd = short tons per day

Table 2-12
Maximum Feeds and Products

Feeds	Maximum Amounts
Feedstock (AR)	3,600 stpd
Fluxant	140 stpd
Water (High Ambient)	4,100 gpm
Products and Byproducts	**Maximum Amounts**
Maximum Net Power: Normal Baseload Low-Carbon Power Maximum Power Capability [1]	 250 MW 400 MW
Carbon Dioxide	8,400 stpd
Sulfur	180 stpd
Gasification Solids (wet)	750 stpd

Source: HECA Project

Notes:
[1] Maximum power capacity as submitted in the CAISO Interconnection Request
AR = as received
CAISO = California Independent System Operator
gpm = gallons per minute
MW = megawatt
stpd = short tons per day

Overall gasification reactions are shown in Table 2-13, Primary Gasification Reactions. Some of these reactions are actually endothermic, requiring heat input to go forward—unlike combustion, which is completely exothermic.

Table 2-13
Primary Gasification Reactions

Devolatilization/Pyrolysis = CH_4 + CO + Oils + Tars + C (char)	
$C + O_2 \rightarrow CO_2$	Oxidation – exothermic – rapid
$C + \frac{1}{2} O_2 \rightarrow CO$	Partial oxidation – exothermic – rapid
$C + H_2O \rightarrow CO + H_2$	Water/gas reaction – endothermic – slower than oxidation
$C + CO_2 \rightarrow 2CO$	Boudouard reaction – endothermic – slower than oxidation
$CO + H_2O \rightarrow CO_2 + H_2$	Water gas shift reaction – exothermic – rapid
$CO + H_2 \rightarrow CH_4 + H_2O$	Methanation – exothermic
$C + 2H_2 \rightarrow CH_4$	Direct methanation – exothermic

Source: Multiple Publicly Available Sources

Notes:
C = carbon
CH_4 = methane
CO = carbon monoxide
CO_2 = carbon dioxide
H_2 = hydrogen
H_2O = water
O_2 = oxygen

Gasification is a chemical conversion process that occurs in a reducing environment. Gasification differs from combustion in that gasification produces syngas, an intermediate product that can then be used for other purposes such as generating electricity or producing chemicals. Typical components of syngas from an oxygen-blown gasifier are shown in Table 2-14, Components of Syngas from Oxygen-Blown Gasification.

Table 2-14
Components of Syngas from Oxygen-Blown Gasification

Constituent	Percent by Volume
Hydrogen	24 to 40
Carbon monoxide	35 to 50
Carbon dioxide	2 to 30
Water	0.4 to 23
Methane	0 to 4
Hydrogen Sulfide	0.2 to 2.0
Carbonyl sulfide	0 to 0.1
Nitrogen + Argon	0.2 to 7
Ammonia + Hydrogen cyanide	0 to 0.3
Higher Heating Value	~200-300 Btu/scf

Notes:
Btu = British thermal unit
scf = standard cubic foot

The primary components of syngas are carbon monoxide and hydrogen. Syngas must be thoroughly cleaned prior to further use, especially if it will be used in a combustion turbine or for producing chemicals.

While the term "IGCC" usually implies coal gasification, feedstocks typically include coal (bituminous, sub-bituminous, and lignite), petcoke, biomass, and blends of these materials. The Project will use petcoke and coal/petcoke blends.

2.2.2 Feedstock Delivery, Handling and Storage

A simplified process flow diagram of the Feedstock, Handling, and Storage system is shown in Figure 2-12, Flow Diagram: Feedstock Handling and Storage.

Petcoke and Coal Handling

The primary feedstocks for this Project are petcoke from California refineries and western bituminous coal. Petcoke will be delivered to the plant via truck. Western bituminous coal will be brought by rail to an existing delivery point in the vicinity of the Project Site, trans-loaded to trucks, and delivered to the Project. The average number of daily feedstock truck deliveries (accounting for the variability in feedstock composition) is 115. The maximum is 180.

Feedstock trucks will be unloaded into hoppers inside a truck-unloading building, which will be provided with dust abatement systems. The feedstock will be transported via enclosed conveyors to one of three cone-bottom feedstock storage silos.

Feedstock reclaimed from the silos will be transported via an enclosed conveyor to a pre-crushing system and then to the feedstock bins in the Grinding and Slurry Prep building. Feedstock blending (when required) will be accomplished by reclaiming appropriate amounts of feedstock simultaneously from multiple feedstock storage silos.

Tramp metal removal will be accomplished using magnets and metal detectors. A dust collection system consisting of hoods and baghouses will control particulate emissions.

On-site feedstock storage will include active storage in the feedstock storage silos and inactive emergency storage in an open pile covered with stabilizer. Buildup and reclaiming of the inactive emergency storage pile will be accomplished using mobile equipment.

Fluxant

Fluxant is added to the feedstock when required to achieve the proper molten flow characteristics of the gasification solids at acceptable gasifier operating temperatures.

Fluxant will be delivered to the Project Site via truck from regional sources. The average number of fluxant truckloads to be delivered each day (accounting for the variability in feedstock fluxant requirements) is 3. The maximum is 9. The fluxant trucks will be unloaded using a pneumatic transport system into the fluxant storage bins. A dust collection system consisting of hoods and baghouses will control particulate emissions.

2.2.3 Gasification

Gasification Technology Selection

GE quench gasification technology was identified as the best fit to meet the specific requirements of the proposed Project, when taking into account key decision criteria, including the lifecycle cost of electricity and reducing technology risk through demonstrated commercial operation with similar feedstocks (petcoke and coal), at similar capacity and operating conditions. As part of the design evaluation, both of GE's gasification designs were evaluated; these are referred to as radiant and quench. GE's radiant design has been incorporated in their IGCC reference plant, and GE considers it to be the preferred choice for IGCC power plants that do not require high levels of carbon capture. GE's quench design is simpler and has been applied widely in syngas generation for chemical production, particularly where sour shift is used to increase syngas hydrogen (and carbon dioxide) content. The Project uses GE's quench gasification technology because of the synergies with the sour shift process that increase hydrogen production and facilitate high levels of pre-combustion carbon capture (carbon dioxide removal).

GE's quench gasifier design routes the hot gasifier effluent directly into a water bath at the bottom of the gasifier without any high-level heat recovery. Molten gasification solids in the gasifier effluent are solidified in the water bath and removed, and the resultant gas is scrubbed to remove fine particulates. Both designs also have similar grinding and slurry preparation systems and gasification solids handling systems. Figure 2-13, Gasification Process Sketch for Permits, shows a schematic process sketch of GE's quench gasification technology.

Grinding and Slurry Preparation

Feedstock is continuously delivered from feed bins to the grinding mills. Fluxant is also continuously conveyed from feed bins to the grinding mills.

The grinding mills crush the feedstock, fluxant, and recycled gasifier solids (fine slag/ash and unconverted carbon) with water to form a slurry. The slurry is pumped into slurry tanks, which are sized to provide about 8 hours of storage.

Gasifiers

GE's quench gasifier is a slurry-fed, pressurized, entrained flow, slagging downflow gasifier, consisting of a refractory-lined pressure vessel capable of withstanding the required gasification process temperature and pressure range. For the gasification reaction, slurry and oxygen are introduced into the gasifier through a specialty equipment item called the feed injector.

All slagging gasifiers require that the mineral matter in the feedstock melt and flow by gravity out the bottom of the gasifier reaction chamber. When using petcoke feedstock and/or coal feedstocks containing ash that melts at high temperatures, the addition of a fluxant is required to achieve the proper molten "gasification solids" flow characteristics at acceptable gasifier operating temperatures, and thus facilitate gravity flow. Both the type and quantity of fluxant required depend upon the feedstock characteristics.

The slurry is pumped from the slurry tanks to each gasifier by a slurry charge pump. This high-pressure metering pump supplies a steady, controlled flow of slurry to the feed injector. The slurry and a measured amount of high-pressure oxygen from the ASU react in the gasifier reaction chamber at high temperatures to produce syngas. The feedstock is almost totally gasified in this environment to form syngas consisting principally of hydrogen, carbon monoxide, carbon dioxide, and water.

Hot syngas, along with ash, fluxant, and unconverted carbon from the gasifier reaction chamber flow down into the water-filled quench chamber below the gasifier. The syngas is cooled in this water pool, and exits the quench chamber to be further washed. Molten ash and fluxant are solidified in the water pool. Coarse slag and a portion of the unconverted carbon settle to the bottom of the quench pool, where they enter the coarse slag handling section.

Syngas Scrubbing

The syngas from the gasifier enters the syngas scrubber, where solids are removed from the syngas. Raw syngas from the overhead of the syngas scrubber is routed to the downstream sour shift and low-temperature gas-cooling section.

Water condensed from the syngas in the downstream sour shift and low-temperature gas cooling section is returned as process condensate to the syngas scrubber. The syngas scrubber bottoms water contains solids removed from the raw syngas exiting the quench pool.

Gasification Solids and Water Handling

Gasification solids (slag as defined by GE) are comprised of ash, fluxant, and unconverted carbon that exit the gasifier. Gasification solids and water handling includes handling sections for both coarse and fine slag.

The coarse slag handling section removes coarse solid material from the gasifier. Coarse solid material exiting the bottom of the gasifier quench pool flows into the lockhopper, and the particles settle to the bottom. The solids that accumulate in the lockhopper are water-flushed into the slag collection sump, using process water return from the fine slag handling section.

In the slag collection sump, the gasification solids are separated from the water. The gasification solids are washed, and the washed low-carbon gasification solids are transported by truck off site for sale or disposal. The fine slag recycle from the slag collection sump is pumped to the fine slag handling section.

The water used in the gasifiers, syngas scrubbing, and gasification solids handling sections is referred to as black water. The solids-laden water in the gasifier quench pool is blown down to the fine slag handling section. This black water is sequentially let down in pressure through a series of flash drums, where all dissolved gases flash out of the black water. The flash gases are combined and sent to the SRU. A settler tank is used to concentrate the solids in the black water. The overflow process water from the settler is pumped to the syngas scrubbing section. Part of the process water is also sent to the lockhopper for flushing in the coarse slag handling section. A small fraction of the process water is discharged as gasification blowdown water to the process wastewater treating/ZLD system.

Most or all of the settler bottoms are pumped to the grinding and slurry preparation section to recycle fines. Some of the settler bottoms can alternatively be sent to a fine gasification solids filter to produce filter cake, which can be either recycled to the grinding and slurry preparation section or transported by truck off site for disposal.

Gasifier Refractory Heaters

Natural gas-fired gasification refractory heaters are required to preheat the gasifier refractory prior to startup if starting from cold conditions. The combustion products from the gasification refractory heaters are released through vent stacks located on top of the gasifier structures.

2.2.4 Sour Shift/Low Temperature Gas Cooling

The Sour Shift/Low Temperature Gas Cooling (LTGC) unit performs several functions:

- Substantially increases the syngas hydrogen content using a two-stage carbon monoxide shift process

- Cools the shifted syngas by generating steam for additional power production and for internal plant consumption
- Collects hot process condensate formed during the shifted syngas cooling process for recycling in the gasifier syngas scrubbing section
- Collects additional process condensate formed during the shifted syngas cooling process for recycling in Gasification and/or discharge to Sour Water Stripping
- Removes ammonia from the cooled syngas

The carbon monoxide shift process converts water vapor and carbon monoxide to hydrogen and carbon dioxide using the water water-gas shift (also known as CO shift) reaction, which can be expressed as follows:

$$CO + H_2O \leftrightarrow CO_2 + H_2 + \text{Heat}$$

The reaction is highly exothermic (i.e., releases heat). High reaction rates are favored by high temperatures; however, high conversion is favored by lower temperatures.

In addition to increasing the hydrogen content of the syngas, the carbon monoxide shift process substantially increases the fraction of carbon present as carbon dioxide in the syngas, and consequently the extent of pre-combustion carbon capture (e.g., as carbon dioxide removal) that can be achieved.

Selection of the carbon monoxide shift technology depends upon whether the process gas is essentially sulfur-free (“sweet”) or contains appreciable quantities of sulfur compounds (“sour”). Iron/chrome oxides (at higher temperatures) and copper/zinc oxides (at lower temperatures) are used as catalysts with sulfur-free gas streams, whereas cobalt-molybdenum oxides are used as catalysts if sulfur tolerance is required.

Sulfur-tolerant, sour shift technology was selected for the Project because the sour syngas produced by GE’s quench gasification process also contains a substantial amount of water vapor, which drives the carbon monoxide shift reaction to near completion, maximizing the potential for carbon capture. The many synergies between the two technologies yield a simple and cost-effective means of achieving high carbon capture with only a single carbon dioxide absorption step. Additionally, the low concentration of carbon monoxide in the shifted syngas allows production of a carbon dioxide by-product gas with a carbon monoxide content of less than 800 parts per million by volume (ppmv). Examples of existing gasification plants with GE’s quench gasification and sour shift technology include the Shell Convent Refinery Hydrogen Plant in Louisiana and the Coffeyville Resources Ammonia Plant in Kansas.

The Sour Shift unit for the Project will be designed with two sour shift reactors in series to achieve a residual carbon monoxide concentration in the cooled, shifted syngas of about one volume percent. As a co-benefit, the carbon monoxide shift process will also substantially reduce carbonyls, formates, cyanides, and other impurities in the syngas.

Simplified process flow sketches of the Sour Shift/LTGC unit are included in Figure 2-14, Flow Diagram: Sour Shift System, and Figure 2-15, Flow Diagram: Low Temperature Gas Cooling. The following discussion provides a brief description of the processing steps in this unit.

Scrubbed syngas from the Gasification Unit is heated against hot reactor effluent and fed to the two sour shift reactors in series. The sour shift catalyst also promotes conversion of most of the carbonyl sulfide (COS) present in the syngas to hydrogen sulfide (H_2S) via the following reaction:

$$COS + H_2O \leftrightarrow CO_2 + H_2S$$

The shift reactions are highly exothermic, and the hot syngas is cooled between the two shift reactors by feed/effluent exchange and by raising steam for generating additional power and internal plant consumption.

The shifted syngas from the second shift reactor is cooled by generating steam at multiple pressure levels, and by heating boiler feedwater and vacuum condensate to efficiently use the available but relatively low-temperature heat. Final cooling of the shifted syngas to near ambient temperature is achieved with air and water coolers.

Water condenses from the shifted syngas as it is cooled. The majority of the ammonia (NH_3) and a small portion of the carbon dioxide and hydrogen sulfide present in the syngas are absorbed in this condensed water. A fraction of this process condensate is reheated against shifted syngas and returned as hot process condensate to the syngas scrubbers in the Gasification Unit, and the rest is routed to the Sour Water Stripping unit.

The cooled shifted syngas is washed with cold water in a trayed column to remove residual ammonia, and then fed to the Mercury Removal unit.

A simplified process flow sketch of the Mercury Removal System is shown in Figure 2-16, Flow Diagram: Wash Column and Mercury Removal.

2.2.5 Mercury Removal

Tests of petcoke sources show occasional trace levels of mercury in the elemental analyses. Western bituminous coals typically contain trace levels of mercury as well. In order to minimize potential mercury emission, the Project has incorporated mercury capture technology. The petcoke and coal procurement requires purchase of spot market supplies, effectively limiting the potential for controlling the supplier's processes. However, the mercury capture technology will also ensure that spot market supplies do not introduce mercury emissions.

Downstream of the shift reactors and low-temperature gas cooling, the syngas passes through fixed beds of activated carbon that are prepared with special impregnate additives to remove mercury, if any is present. Multiple beds are used to obtain optimized adsorption. After mercury removal, the product syngas is treated in the Acid Gas Removal (AGR) unit.

2.2.6 Acid Gas Removal System

The term "acid gas" refers to materials containing significant concentrations of acidic gases such as hydrogen sulfide. This section describes how acid gas will be removed from the shifted syngas to produce the hydrogen-rich fuel for the power block.

Rectisol Process Description

The Rectisol process is shown in Figure 2-17, Flow Diagram Acid Gas Removal/Fuel Gas Supply Systems. Shifted, hydrogen-rich sour syngas feed is chilled and enters the pre-wash section of the hydrogen sulfide absorber column where condensed or dissolved impurities are removed. The gas then flows up the column where it is contacted with carbon dioxide–laden methanol solvent for absorption of hydrogen sulfide and other sulfur compounds. The solvent preferentially absorbs sulfur, releasing carbon dioxide in the process. The now hydrogen-sulfide–laden solvent is withdrawn from the chimney tray of the column and flashed, with the flash gas being recycled to the hydrogen sulfide absorber column and the separated liquid solvent sent to a hot regenerator.

Overhead gas from the hydrogen sulfide absorber flows to the carbon dioxide absorber where it is contacted with cold regenerated solvent for carbon dioxide removal. The treated hydrogen-rich gas, now very low in hydrogen sulfide and carbon dioxide, exits the top of the carbon dioxide absorber and is heated before flowing to a turbo expander for energy conservation. The hydrogen-rich product gas is then heated and used as fuel in the combined cycle power block.

Carbon dioxide–laden solvent flows from the bottom of the carbon dioxide absorber column, where a portion is diverted to the hydrogen sulfide absorber for hydrogen sulfide removal. The remainder is flashed, with the separated gases recycled to the hydrogen sulfide absorber, and chilled before being routed to the flash regenerator. In the flash regenerator, absorbed carbon dioxide is removed from the solvent by sequentially decreasing the pressure in multiple steps. Separated carbon dioxide flows to carbon dioxide compression equipment for transportation to the Elk Hills Field for CO_2 EOR and sequestration.

Carbon dioxide-free solvent from the bottom of the flash regenerator combines with solvent from the hydrogen sulfide absorber and flows to the hot regenerator where hydrogen sulfide and other sulfur compounds are released from the solvent by increasing the temperature and stripping with methanol vapor generated in a reboiler. The separated acid gas undergoes further processing for recovery of the sulfur. Most of the regenerated solvent, now carbon dioxide- and hydrogen sulfide-free, is cooled by heat exchange with cool solvent, chilled, and returned to the carbon dioxide absorber for reuse. A small portion of the regenerated solvent and the bottom liquid of the hydrogen sulfide absorber column that contains water from the feed gas are sent to the methanol-water column for separation of dissolved water and impurities from the methanol by distillation. The methanol overhead is returned to the hot regenerator and the separated column bottoms water is cooled and sent to the gasification area.

2.3 POWER GENERATION

2.3.1 Summary

The combined cycle portion of the power block is similar to a state-of-the-art combined cycle power plant. Major equipment consists of a heavy duty gas turbine, a steam turbine and an HRSG. Other power block equipment includes a condenser, cooling tower, deaerator, boiler feedwater and condensate pumps. Power is produced by the consumption of hydrogen-rich fuel to meet the parasitic load for the accompanying gasification plant and for export to the PG&E electrical grid. Natural gas can be co-fired with hydrogen-rich fuel when only one gasifier is operating. Natural gas firing also serves as a backup fuel to allow continued electrical power export when hydrogen-rich fuel is not available. The power block integrates the process heat generated within the gasification plant by the exothermic water-gas shift reaction and the SRU hydrogen sulfide oxidation reaction. Boiler feedwater from the power block deaerator is supplied to generate saturated steam at multiple pressure levels using this heat. Excess high-pressure (HP), intermediate-pressure (IP) and low-pressure (LP) steam, and steam generated in the HRSG with gas turbine exhaust heat and duct burner heat release are superheated in the HRSG before being admitted to the reheat steam turbine generator (STG).

The STG exhausts into a water cooled condenser, where the heat is rejected to a multi-cell mechanical draft wet cooling tower via a circulating water system. The condensate leaving the condenser hot well is heated and deaerated before returning to the HRSG LP system and integrated process heat exchangers.

The power block also includes a single natural gas–fired auxiliary gas turbine, an aeroderivative simple cycle machine, to provide backup power to the gasification plant during forced outage periods and to provide beneficial spot market power production to the grid.

Both the heavy duty and aeroderivative gas turbines in the power block incorporate diluent injection and post-combustion control technologies to meet the stack emissions requirements.

Utilities are supplied to the power block from off-site (natural gas) or from other operating units within the facility (hydrogen-rich fuel from the gasification block, makeup and demineralized water from the water treatment plant, and nitrogen diluent from the ASU). Electrical power generation is distributed in the switchyard for transmission to the grid or for satisfying the auxiliary loads within the facility.

2.3.2 Major Power Block Equipment Description

The major equipment is described in the following sections, covering the topics of fundamental operation and the function within the power block and overall facility. Equipment highlights are provided. An overall sketch of the power block system is shown in Figure 2-18, Flow Diagram Power Block Systems.

2.3.2.1 Heavy Duty Combustion Turbine Generator

The heavy duty CTG is made up of an axial flow air compressor, diffusion-flame combustion system, an axial flow turbine, and a hydrogen-cooled generator. Ambient air is filtered and cooled in an evaporative cooler before entering the compressor section. The compressor is multi-stage design, which nearly adiabatically compresses the air through a process of transferring the energy imparted by the rotating blade to pressure rise in the diffusing stationary blade. This compression process also raises the air temperature before discharging to the combustion system. The compressor has air extraction ports on the outer stationary shell and the inner rotor. During startup, air is extracted from the shell side to balance the flow passing ability of the front stages with the later stages. During normal operation, air is extracted for cooling the hot gas path parts that make up the turbine section. Air extracted through the outer shell is used to cool the stationary turbine parts, including the nozzles, bucket stationary shrouds, and the turbine shell. Air extracted inward through the rotor supplies cooling air for the inner passages and rotating parts, including the buckets, the rotors, and the wheel spaces between the rotors.

Air leaves the compressor at elevated pressure and temperature, and enters the combustion section. The combustion system is made up of multiple combustion cans (chambers) that equally divide the flow, allowing for controlled combustion reaction zones. Each combustor can have a set of hydrogen fuel and natural gas fuel nozzles, as well as nitrogen and steam diluent injection nozzles. Dilution holes in the combustion liners are designed to control the combustion zone air, fuel, and diluent mixing in such a way as to suppress the combustion temperatures and thus limit the amount of nitrogen oxides formed. The hot combustion gases leave the combustion system through the transition piece and enter the turbine section.

The high-pressure and high-temperature gas entering the turbine passes through the stationary nozzle to the rotating bucket. There are three such stages in the turbine that extracts energy from the expanding gases, providing the torque that drives the axial compressor and the generator. The machine is a cold-end drive design, where the shaft torque generated in the turbine section is transmitted through the compressor shaft to the generator. This allows for the turbine exhaust gas leaving the last rotating bucket to enter a long diffuser, where velocity or kinetic energy is converted to pressure or potential energy. The advantage of the diffuser is that it allows the turbine to operate at a lower back pressure, increasing power generation. Flow exiting the diffuser enters the HRSG transition duct upstream of the first superheater coils.

The hydrogen-cooled generator shaft is connected through a coupling to the CTG shaft at the compressor end of the machine. The generator typically converts mechanical energy to electrical energy, with additional auxiliary loads required to energize the excitation system, operate the lubricating oil system, and other support systems. Mechanical losses from the bearings also take away from the net electrical generation. Hydrogen is used as the coolant, which requires carbon dioxide and compressed air purging systems to ready the generator for safe maintenance.

The CTG operation is supported by separate skids that house the lube oil system, the fuel, and diluent metering systems, and other services, including fire detection and protection, control system, and compressor wash system, etc. The enclosure around the CTG has a controlled operating environment, with a ventilation system designed to protect against undesirable outside temperatures and maintain safe conditions, with fire detection and protection.

Table 2-15, Combustion Turbine Generator, summarizes the combustion turbine model, fuels, temperature ranges, output and other aspects relevant to the Project.

2.3.2.2 Heat Recovery Steam Generator

The CTG exhausts into the HRSG after a short transition duct. The HRSG is a triple-pressure level reheat design. The HRSG is comprised of a series of heat exchangers that use the CTG exhaust energy to heat boiler feedwater to saturation conditions, then vaporize and superheat the steam. Also, HP STG exhaust steam is reheated in the HRSG before being returned to the intermediate pressure (IP) section of the STG. The HRSG includes a duct burner to elevate the exhaust gas temperature, a selective catalytic reduction (SCR) system to control the stack

Table 2-15
Combustion Turbine Generator

Model	GE PG7321 (FB) w/IGCC Combustor
Fuels	H_2-Rich Fuel, Natural Gas, Co-Firing
Inlet Air Cooling	Evaporative Coolers, 85% Effectiveness
Emissions Control Diluent	Nitrogen for H_2-rich fuel, Steam Injection for Natural Gas
Ambient Temperature Range	20°F to 115°F, Average 65°F
Ambient Pressure/Elevation/Elevation	14.54 psia/288 feet above msl
Exhaust Pressure Loss @ ISO	18.0 inches H_2O
Air Extraction	Not Included, limited for high H_2 fuels
H_2 & Diluent Temperature	400°F at the GE interface
Base Load Generator Output	232 MW, drops off at higher ambient temperature
Exhaust Flow & Temperature	4,104 kpph, 1,053°F @ average ambient temperature
Min Output in Emissions Compliance	60 percent of Base Load

Source: General Electric

Notes:
°F = degrees Fahrenheit
GE = General Electric
H_2 = Hydrogen
H_2O = water
IGCC = Integrated Gasification Combined Cycle
IGV = inlet guide vane
ISO = International Standards Organization standard conditions of 1 atmosphere 59° F, and 60 percent relative humidity
kpph = kilopounds per hour (thousands of pounds per hour)
msl = mean sea level
psia = pounds per square inch absolute

nitrogen oxide emissions, and a carbon monoxide catalyst system to control the stack carbon monoxide emissions.

Each HRSG pressure level system consists of economizing, evaporating, and superheating sections. The LP economizer is fed from the deaerator and the IP and HP economizers are fed from the LP drum. Condensate enters the HRSG feedwater heater section after leaving the condenser hotwell, combined with the makeup water and heated with process heat. The feedwater heater heats the feedwater to within 20°F of the deaerator saturation temperature at the deaerator operating pressure of 30 pounds per square inch absolute (psia). The off-base deaerator uses stripping steam from the LP drum to remove entrained oxygen before supplying the HRSG and the process LTGC system with boiler feedwater.

The LTGC system transfers heat from the hot syngas, leaving the shift converters to a multi-pressure level system that generates saturated steam from deaerated feedwater. This steam satisfies the requirements of the gas processing units and other users, with the excess HP, IP, and LP saturated steam sent to augment HRSG steam production.

2.3.2.3 Emissions Controls Systems

The Project is designed with state-of-the-art emission-control technology. Emissions control systems will be designed to meet the Best Available Control Technology (BACT) levels of nitrogen oxides, carbon monoxide, sulfur dioxide, and volatile organic compounds (VOCs), as proposed in this Revised AFC, based on the most current industry data and manufacturers' information. Project emission control systems are described in detail below.

SCR Emissions Control System

The SCR system reduces nitrogen oxide emissions from the HRSG stack gases by up to about 83 percent. Diluted 19 percent aqueous ammonia is injected into the stack gases upstream of a catalytic system that converts nitrogen oxide and ammonia to nitrogen and water.

The expected components in the SCR system are as follows:

Aqueous Ammonia Storage Tank – The aqueous ammonia storage tank is a horizontal or vertical vessel that stores 20,000 gallons of 19 percent by weight aqueous ammonia for the SCR system. The storage tank will be complete with relief valves, level gauges, local audio alarms, and will also be located inside a containment area.

Aqueous Ammonia Forwarding Pumps – The aqueous ammonia forwarding pumps will transfer aqueous ammonia from the storage tank to the aqueous ammonia vaporizer.

Ammonia Vaporizer – The aqueous ammonia vaporizer atomizes and vaporizes the ammonia and water solution. Plant air or steam will atomize the aqueous ammonia to assist in the vaporization. The energy to vaporize the aqueous ammonia will come from a slip stream of hot stack gas or by heating ambient air with a heating element.

Vaporizer Blower – The vaporizer blower delivers fresh air or recycled hot stack gas from the HRSG into the aqueous ammonia vaporizer.

Ammonia Injection Grid – Once the aqueous ammonia is properly vaporized, the ammonia is sent to an injection grid where the ammonia stream is divided into various injection points upstream of a catalyst. The flow of ammonia to each injection point can be balanced to provide optimum nitrogen oxide reduction.

SCR Catalyst – The SCR catalyst provides the surface area and the catalyst for ammonia and nitrogen oxide to react and form nitrogen and water. The SCR catalyst will be installed in a reactor housing located within the HRSG at the proper flue gas temperature-point for good nitrogen oxide conversion.

CO Oxidation System

A carbon monoxide catalyst will be installed in the HRSG casing upstream of the SCR ammonia injection location to reduce carbon monoxide emissions. The carbon monoxide catalyst will oxidize the carbon monoxide and VOCs produced from the CTG.

Continuous Emissions Monitoring System

The Continuous Emissions Monitoring System (CEMS) records the emissions out of the HRSG stack to comply with local, state, and federal emission requirements. The CEMS monitors the nitrogen oxide, oxygen, and carbon monoxide levels. It uses control system signals for CTG power output and fuel gas to the CTG to calculate the total mass rate of emissions released, and may also be used as part of the ammonia injection controls for the SCR system. The CEMS will be designed, installed, and certified in accordance with the applicable San Joaquin Valley Air Pollution Control District (SJVAPCD) and U.S. Environmental Protection Agency standards for analyzer performance, data acquisition, and data reporting.

2.3.2.4 Steam Turbine Generator

The STG is a 160 MW (nominal) sliding-pressure reheat design, with the HP section discharge steam sent back to the HRSG to be reheated before admission to the IP section. The IP section discharges into the crossover pipe where LP steam from the HRSG is admitted before entering the double flow LP section. The flow splits and expands through separate LP turbines before exhausting downward into the condenser. The turbine sections are on a common shaft, which connects through a coupling to a hydrogen-cooled generator.

The STG has supporting systems, including a gland steam condenser, a steam seal regulator, lube oil and hydraulic oil systems, and a control system. The steam seal system manages the use of leakages from the HP section seals to provide sealing for the lower pressure sections, as well as provide excess steam to the gland seal condenser.

2.3.2.5 Heat Rejection System

The excess thermal energy in the steam exhausted to the condenser is dissipated in the heat rejection system. This system is comprised of a condenser, a circulating water system, and a multi-cell cooling tower.

The condenser is a shell and tube heat exchanger with the steam condensing on the shell side under a vacuum and the cooling water flowing through the tubes in a single or double pass design. The shell side operates in a typical pressure range of 0.9 inch mercury, absolute pressure (HgA) to 2.4 inches HgA. The condensate collects in the condenser hotwell, where it supplies the condensate pumps that feed the HRSG.

The heat in the condenser is picked up by the circulating water system and transferred to the cooling tower. An auxiliary cooling water system also transfers heat to the cooling tower from the cooling duties of the hydrogen-cooled generators, the auxiliary CTG, and other power block equipment.

2.3.3 Auxiliary Combustion Turbine Generator

The auxiliary CTG is a natural gas–fired GE LMS100® PA in a simple cycle configuration, equipped with water injection for nitrogen oxide control. Post combustion emissions controls will include SCR and carbon monoxide catalyst systems to meet the permitted stack emissions. Table 2-16 summarizes the details of the Auxiliary CTG.

Table 2-16
Auxiliary Combustion Turbine Generator

Model	GE LMS100® PA
Fuel	Natural Gas
Inlet Air Cooling	Evaporative Coolers, 85 % Effectiveness
Emissions Control Diluent	Water Injection
Ambient Temperature Range	20°F to 115°F, Average 65°F
Ambient Pressure/Elevation / Elevation	14.54 psia/288’
Exhaust Pressure Loss @ ISO	12.0 inches H_2O
Compressor Intercooler	100°F Return Air Temperature
Base Load Generator Output	103.1 MW @ 65°F Ambient
Stack Emissions Control	SCR for NO_x and CO Catalyst for CO and VOCs
Min Output in Compliance	50% of Base Load

Notes:
% = percent
CO = carbon monoxide
CTG = combustion turbine generator
°F = degrees Fahrenheit
H_2O = water
ISO = International Standards Organization standard ambient conditions (one atmosphere, 59°F, 60% relative humidity)
MW = megawatts
NO_x = nitrogen oxide
psia = pounds per square inch, absolute
SCR = selective catalytic reduction
VOC = volatile organic compounds

The basic components of the auxiliary CTG are a compressor, combustor, turbine, and generator. This model integrates features of GE’s heavy-duty frame design and aeroderivative technology. Unlike the 7FB heavy duty design, the LMS100® is a multi-shaft machine, with the LP compressor (LPC) and the IP turbine (IPT) on a common shaft, the HP compressor (HPC) and HP turbine (HPT) on a common shaft and an independent power turbine on a common shaft with the generator. The LPC is derived from an existing heavy-duty frame machine design with several years of field experience. The HPC, HPT, and IPT sections, referred to as the super-core, are based on proven aeroderivative technology with many millions of operating hours. The power turbine, a new design optimized to operate in either the 50 Hertz (Hz) or 60 Hz market, is pneumatically coupled to the super-core and transmits power to the generator.

Featured also is an intercooler, between the LPC and the HPC, which cools the air entering the HPC, reducing compressor power demand, and increasing air flow and pressure ratio capability. The intercooler rejects heat to the auxiliary cooling system and ultimately to the power block cooling tower.

A single annular combustor system, a common aeroderivative design, is used, with water injection to control nitrogen oxide emissions. Post-combustion emission controls include an SCR and carbon monoxide catalyst.

The auxiliary CTG is equipped with the following accessories to provide safe and reliable operation: evaporative coolers, inlet air filters, metal acoustical enclosure, duplex shell; and tube lube oil coolers for the turbine and generator, compressor water wash system, fire detection and protection system, hydraulic starting system, and compressor variable bleed valve vent.

2.3.4 Major Electrical Equipment and Systems

The Project electrical distribution system configuration is shown on Figures 2-19 through 2-22, Electrical Overall One-Line Diagrams.

The Project will have a 230-kV air-insulated switchyard using a breaker and a half scheme with redundant 230-kV transmission lines for interconnection to the PG&E Midway Substation. The breaker and a half scheme allows each breaker to be isolated and also each 230-kV bus to be isolated without affecting the reliability of the Project. Each of the 230-kV transmission lines is sized for the total plant output. Revenue metering is provided on each of the transmission lines to PG&E.

The combined cycle power block has two prime movers: the GE Frame 7FB (CTG-1) and the associated steam turbine generator (STG-1) (see Figures 2-19, Electrical Overall One-Line Diagram). CTG-1 and STG-1 each have 18-kV generator breakers. The auxiliary simple cycle (CTG-2) provides an independent source of generation when the combined cycle gas turbine CTG-1 is not operating, or when additional peaking power is needed. The CTG-2 uses 230-kV generator breakers.

Startup power for the Project will be obtained by back feeding from the 230-kV grid through the main transformer to the unit auxiliary transformers which are tap connected to the CTG-1 and STG ISO phase buses (see Figure 2-20, Electrical Overall One-Line Diagram).

The Project's auxiliary loads are served by various Power Distribution Centers (PDCs). PDC-1 and PDC-2 serve major 13.8-kV loads excluding the ASU loads that are supplied from a dedicated 230-13.8-kV transformer. The 13.8-kV AGR refrigeration compressor, the 13.8-kV carbon dioxide compressor, as well as the medium voltage PDCs are fed from PDC-1 and PDC-2. Each of the 4,160-volt (V) and 480-V PDCs have a double ended substation with two 100 percent sized transformers.

Dual 2 MW standby diesel generators (see Figure 2-21, Electrical Overall One-Line Diagram) provide emergency power to essential services in the event of a grid failure.

Medium voltage (MV) and low voltage (LV) switchgear, MV and LV motor control centers (MCCs), 125 Vdc batteries, chargers, uninterruptable power supply (UPS), and Distributed Control System (DCS) I/O racks shall be located indoors in pre-fabricated electrical PDCs with redundant heating, ventilation, air conditioning units. The Major Electrical Equipment will be in accordance with American National Standards Institute (ANSI)/Institute of Electrical and

Electronic Engineers (IEEE)/National Electrical Manufacturers Association/American Society for Testing and Materials standards. The electrical system design and installation shall be in accordance with the National Electrical Code. For specific details of the Major Electrical Equipment, refer to Appendix B – Electrical Design Criteria.

2.4 SUPPORTING PROCESS SYSTEMS

2.4.1 Natural Gas Fuel System

2.4.1.1 Natural Gas Metering Station

The natural gas fuel system provides natural gas to all the Project components at the required pressure, temperature, and flow rates. The natural gas system is shown on Figure 2-23, Flow Diagram: Natural Gas System. The natural gas underground pipeline enters the Project Site at the Natural Gas Metering Station. The metering station is provided by the gas supplier and contains the gas revenue meters and gas analyzers. The gas metering station also contains a knockout drum, which is included as a precaution against any liquids that could get into the main gas pipeline. The Project takes custody of the natural gas at the outlet of the metering station.

2.4.1.2 High-Pressure Natural Gas

The power block combined cycle CTG (GE Frame 7FB) is the largest high-pressure natural gas user, although hydrogen-rich gas is the primary fuel for this unit. All of the combined cycle startups are on natural gas, and the power block can operate independently on natural gas when hydrogen-rich fuel is not available. The combined cycle CTG requires natural gas at about 400 psig, which is near the minimum operating pressure of the pipeline. When the pipeline pressure is higher than the CTG requires, the gas pressure is let down in a pressure control station. The natural gas to the CTG passes through a knockout drum, is heated to about 50°F above the natural gas dew point with an electrical heater, and is filtered before entering the CTG fuel control skid.

The auxiliary simple cycle CTG (GE LMS100®) requires a booster compressor to increase the natural gas pressure to about 960 psig at the fuel control skid. The heat of compression will ensure that the gas is above the dew point, and a filter separator is included to make sure only clean dry natural gas enters the CTG.

2.4.1.3 Low-Pressure Natural Gas

Low-pressure natural gas will be supplied from a letdown station in the power block. A separate pressure-reduction station and knockout drum are provided to supply the Project's other low-pressure natural gas users:

- HRSG duct burners (when combined cycle plant is operating on natural gas fuel)
- Auxiliary boiler
- SRU reaction furnace (for refractory preheating and startup)
- Gasifier preheat burners (for refractory preheating during startup)
- Tail gas thermal oxidizer

- Gasification, Rectisol and SRU flare pilots
- Building space heating and miscellaneous users

2.4.2 Air Separation Unit

High purity oxygen and nitrogen are supplied from the ASU, which separates and purifies oxygen and nitrogen from the ambient air. The ambient air is filtered, compressed, dried, and cooled to cryogenic temperatures, and is then separated into purified oxygen and nitrogen streams.

Most of the high purity oxygen is supplied at high pressure to the gasification process as one of its feeds. The rest is supplied at low pressure to the oxygen-blown SRU as one of its feeds.

High-purity nitrogen (less than 1 percent oxygen) is supplied at medium pressure as a diluent to the combustion turbine, which uses it to reduce thermal nitrogen oxide formation when combusting the hydrogen-rich gas. Ultra-high purity nitrogen (less than 100 ppmv oxygen) is used for purging and blanketing throughout the Project.

The oxygen and nitrogen are then separated by cryogenic distillation within a heavily insulated "cold box." Because operating temperatures for air separation are at cryogenic levels, distillation equipment is enclosed within cold boxes and insulated from heat leakage. A simple process flow diagram for the ASU is presented as Figure 2-24, Air Separation Unit.

High-pressure gaseous oxygen for gasification is normally supplied from the ASU by pumping liquid oxygen (LOX) to the required pressure and then vaporizing the oxygen. A LOX storage system provides a backup oxygen supply to the gasifiers during short-term trips of the ASU. The LOX system consists of a LOX storage tank, LOX pump, and LOX vaporizer. The gaseous oxygen exiting the vaporizer is at a pressure suitable for delivery to the gasifier without additional compression.

Gaseous nitrogen for combustion turbine nitrogen oxide control is compressed to delivery pressure in the ASU and sent to the power block. The compressor discharge is not cooled.

Gaseous ultra-high purity nitrogen for purging and inerting of equipment is normally supplied directly to the Project's nitrogen distribution system. A liquid nitrogen (LIN) storage system provides a backup supply of ultra-high purity nitrogen to the plant during ASU trips. The LIN system consists of a LIN tank, LIN pump, and LIN vaporizer. The gaseous nitrogen exits the vaporizer at a pressure suitable for feeding into the Project's nitrogen distribution system.

2.4.3 Sulfur Recovery Unit

Sulfur is removed from the processing facility through a sulfur complex consisting of a Claus unit (thermal stage) plus catalytic converters otherwise known as the Sulfur Recovery Unit (SRU), a Tail Gas Treatment Unit (TGTU), and a tail gas thermal oxidizer. The sulfur process facility consists of 2 by 50 percent SRUs, 1 by 100 percent TGTU, and 1 by 100 percent thermal oxidizer. The Claus unit and TGTU give an overall sulfur recovery efficiency in the range of

99.8 to 99.9+ percent. The following is a process description of the SRU Claus unit, TGTU, and thermal oxidizer.

2.4.3.1 Claus Section

The acid gas stream from the AGR Unit, plus a low concentration acid gas stream from the gasification section and the carbon dioxide/ammonia/hydrogen sulfide stripped from sour water, are fed to two identical, parallel Claus-type SRUs. The total sulfur concentration in the SRU feed (H_2S plus COS) from the AGR will be 45 mol percent (minimum). Pressure at the boundary limit will be 30 psia (minimum).

In the SRU, the hydrogen sulfide carried in the acid-gas streams is converted to elemental sulfur and water vapor based on the industry-standard Claus process. Each unit consists of a thermal stage and two catalytic reaction stages. The sulfur is selectively condensed and collected in molten form in the sulfur pits. The SRU is designed for both air and oxygen-blown Claus technologies. Figure 2-25, Flow Diagram: Sulfur Recovery Unit, presents a simplified process flow sketch of the SRU.

The AGR acid gas and recycle acid gas from the Tail Gas Treating Unit (TGTU) regenerator enter the SRU through the Acid Gas Wash Drum to remove any liquid from operating upsets of upstream units to protect the Claus reaction furnace and catalyst. Similarly, low-concentration acid gas from the gasification section and sour water stripper gas are routed to a Sour Water Stripper (SWS) Acid Gas Knockout Drum.

The resulting acid gas streams are preheated using medium-pressure steam; the oxygen feed is pre-heated using medium-pressure steam prior to feeding the reaction furnace. All of the acid gas from the SWS Acid Gas Knockout Drum and the oxygen is sent to the main reaction furnace to ensure complete destruction of ammonia.

One-third of the hydrogen sulfide is combusted with oxygen to produce the proper ratio of hydrogen sulfide and sulfur dioxide, which then react to produce elemental sulfur vapor in a reaction furnace ($2H_2S + SO_2 \rightarrow 3S + 2H_2O$). A waste heat boiler is used to recover heat before the furnace off-gas is cooled to condense the first increment of sulfur. Gas exiting the first sulfur condenser is fed to a series of heaters, catalytic reaction stages, and sulfur condensers, where the hydrogen sulfide and sulfur dioxide are incrementally converted to elemental sulfur and condensed.

2.4.3.2 Sulfur Storage

Liquid sulfur from the SRU is collected in two fully enclosed subsurface sulfur storage pits (SSPs). To provide for containment, the SSPs are constructed with structural concrete with a solid roof, built in accordance with applicable LORS. The liquid sulfur drains into the SSP which contain a pump well and Sulfur Transfer Pumps. Sweep air is introduced into the SSP to prevent the accumulation of hydrogen sulfide, and to control fugitive emissions. The sweep air inlet and outlet are located at opposite ends of the SSP to ensure proper sweep of the vapor space. The sweep air is drawn through the SSP and routed back to the reaction furnace through the SSP ejector.

Liquid sulfur is pumped from sulfur storage to a sulfur degassing unit. The sulfur degassing unit strips dissolved hydrogen sulfide out of the liquid sulfur. The degassed sulfur is routed from the degassing unit to the sulfur storage SSP. The stripped hydrogen sulfide stream is routed to the Claus reaction furnace.

Sulfur loading involves pumping liquid sulfur from the sulfur storage to trucks. The sulfur loading equipment will have vapor recovery systems to control fugitive emissions by returning displaced vapors to the SRU.

The SRU is a totally enclosed process with no discharges to the atmosphere.

2.4.3.3 Tail Gas Treating Unit

A process flow sketch for the TGTU is shown on Figure 2-26, Flow Diagram: Tail Gas Treating Unit. The tail gas from the SRU is composed mostly of carbon dioxide, water vapor, and sulfur vapor, with trace amounts of hydrogen sulfide, carbonyl sulfide, and sulfur dioxide. The tail gas from both SRU trains is sent to a single TGTU, where it is first preheated using high-pressure steam and then catalytically hydrogenated in the hydrogenation reactor to convert the remaining sulfur species to hydrogen sulfide. The resulting gas stream is then cooled, washed with caustic for unconverted sulfur dioxide removal, and finally contacted with lean amine in the absorber, where hydrogen sulfide is preferentially absorbed. The rich amine leaving the bottom of the absorber is pumped to the regenerator, where hydrogen sulfide and carbon dioxide are stripped from the amine. Overhead gas from the regenerator containing the separated hydrogen sulfide and carbon dioxide is recycled to the front of the Claus SRU section. The lean solvent from the bottom of the regenerator is cooled and pumped to the absorber.

The treated TGTU vent gas from the absorber overhead contains mostly carbon dioxide and trace levels of sulfur compounds. The treated tail gas is normally compressed, dried, and blended with the much larger product carbon dioxide from the AGR unit. The combined carbon dioxide stream is compressed for transportation to the Elk Hills Field for CO_2 EOR and sequestration.

2.4.3.4 Sour Water Stripper

The stripped gasses from the SWS containing ammonia, hydrogen sulfide, and carbon dioxide are sent to the Claus unit for sulfur recovery and ammonia destruction. The SWS is shown schematically on Figure 2-27, Flow Diagram: Sour Water Stripper.

The majority of the SWS feed is produced in the Sour Shift/Low Temperature Gas Cooling Unit. Numerous other small sour water streams are collected from within the Project and sent to the SWS feed tank along with the cold condensate from the shifted syngas knockout drums.

The SWS feed pumps, which take suction from the feed tank, deliver sour water to the SWS. The stripper is injected with low-pressure steam at the bottom of the column. The rising steam strips ammonia, carbon dioxide, and hydrogen sulfide out of the sour water. The overhead vapors are cooled in an air-cooler condenser. The condensate is refluxed back to the column and the overhead non-condensable gases are sent to the Claus unit.

The stripped condensate is drawn off the bottom of the column and pumped to the Gasification Block for reuse.

2.4.3.5 Tail Gas Thermal Oxidizer

Associated with the operation of the sulfur recovery process is the integral use of a thermal oxidizer as a control device to provide for the safe and efficient destruction of the hydrogen sulfide contained in the TGTU vent gas during startup and shutdown. The miscellaneous oxidizing streams from the gasification area (e.g., atmospheric tank vents and miscellaneous equipment vents) are directed to the thermal oxidizer during normal operation to prevent nuisance odors.

In the thermal oxidizer, the TGTU tail gas and other oxidizing streams are subjected to a high temperature and a sufficient residence time to cause an essentially complete destruction of reduced sulfur compounds such as hydrogen sulfide. The thermal oxidizer uses natural gas to reach the necessary operating temperature for optimal thermal destruction.

2.4.4 Process Wastewater Treatment/ Zero Liquid Discharge

A process flow diagram for the process water treatment/ZLD is shown on Figure 2-28. A small fraction of the process water in the Gasification Unit is blown down to the Process Wastewater Treatment/Zero Liquid Discharge (ZLD) unit to maintain the Gasification Unit water chemistry within corrosion limits.

The process wastewater from the Gasification Unit is treated (if required) and routed to a ZLD system, which includes a mechanical vapor compression evaporator and crystallization unit. The pure distillate produced from the evaporator is returned to the Gasification Unit for reuse. The solid material produced will be trucked to an approved off-site material disposal facility in accordance with applicable LORS. An average of less than 1 truckload per day of crystals from both the process wastewater ZLD will be transported offsite. The maximum daily truckloads are anticipated to be 2.

2.4.5 Water Treatment Plant and Plant Wastewater ZLD

The Project will have an on-site water treatment system for the production of varying qualities of water necessary to meet plant-wide requirements. The majority of this treatment system will supply the cooling tower with makeup water. Smaller streams will supply utility water to the gasification system and the evaporative coolers. The power block also requires a supply of high-quality demineralized water. A process flow diagram for the plant wastewater ZLD is shown on Figure 2-29.

The water treatment system and plant wastewater ZLD (Plant ZLD) are integrated. The brackish water supply enters the plant and is passed through green sand filters to remove iron and suspended solids. The iron levels in the cooling tower makeup must be reduced to avoid formation of scale deposits and corrosion to material. Untreated brackish water will also foul downstream nanomembranes.

Water from the green sand filter is routed to a nanofiltration unit for selective ion removal. Based on preliminary process raw water quality data, calcium, sulfate and silica levels will probably need to be reduced. Product water from the nanofiltration system is fed to the cooling tower as makeup and cycled as many times as practically feasible. Cooling tower blowdown, green sand filter backwash water, and nanofiltration reject water are combined and fed to the Plant Wastewater ZLD Unit.

The Plant Wastewater ZLD unit uses a conventional mechanical vapor recompressor Brine Concentrator followed by a Brine Crystallizer to recover water and produce ZLD solids. The ZLD solidsare shipped off site for disposal in accordance with applicable LORS. Recovered water is directed to three locations: a mixed-bed ion exchange, utility water users, and the cooling towers as additional makeup. The mixed-bed ion exchange feeds the power block with high-quality demineralized water. Utility users take ZLD recovered water blended with lower-quality water to achieve a composition that will not damage equipment and that meets end user specifications. This utility water is routed to the Gasification Block, evaporative coolers, and other utility water users. ZLD recovered water not required for mixed-bed ion exchanger feed or utility use is recycled to the cooling tower makeup stream to improve its quality and therefore lower cooling tower makeup water demand. Mixed-bed ion exchange reject, evaporative cooler blowdown, and other water effluent streams are collected and sent back to the ZLD unit. An average of two truckloads per day of ZLD solids will be transported offsite. The maximum daily truckloads are anticipated to be six.

2.4.6 Carbon Dioxide Compression and Pipeline

At least 90 percent of the carbon in the raw syngas will be captured, resulting in a high purity carbon dioxide stream during steady-state operation. The carbon dioxide is transported by pipeline to the custody transfer point at Elk Hills Field for CO_2 EOR and Sequestration. The Carbon Dioxide Compression System is shown in Figure 2-30, Flow Diagram: Carbon Dioxide Compression and Venting Systems. In order for the carbon dioxide to be transported, it must first be compressed. The carbon dioxide that will be compressed comes from two sources: (1) the bulk of the carbon dioxide comes from the AGR unit; and (2) a small portion comes from the TGTU absorber. After processing by the AGR unit, the carbon dioxide is very dry, which avoids pipeline and equipment corrosion.

The AGR removal unit produces high purity carbon dioxide at two pressure levels: (1) the lower pressure level is near atmospheric pressure; and (2) the higher pressure carbon dioxide is available at about three atmospheres. The Rectisol process contacts the syngas with refrigerated methanol so the product carbon dioxide is dry at the compressor suction.

The TGTU carbon dioxide stream is near atmospheric pressure and contains moisture. It is compressed to just above the higher carbon dioxide pressure from the AGR unit, dried, and then combined with the higher carbon dioxide pressure stream from the AGR unit.

The maximum pressure requirement for the carbon dioxide pipeline is about 2,800 psig at the compressor discharge. Once the carbon dioxide pressure reaches approximately about 1,200 psig it becomes super-critical[3]. The significance of this is that at high pressures the carbon dioxide exists as a dense single phase. Heating or cooling the fluid will change its density, but it will not develop into a separate liquid phase. So while the compression to high pressure is needed for carbon dioxide injection operations, it is also needed to keep the carbon dioxide in a super-critical phase throughout the carbon dioxide pipeline. Multi-stage centrifugal compressors have been selected for the Project. The compressors are inter-cooled between stages and provided with inlet guide vane capacity controls.

The captured and compressed carbon dioxide will be transported by pipeline at a pressure greater than 1,500 psig, but no greater than 2,800 psig. The stream will be approximately 97 percent pure carbon dioxide. The pipeline facilities will consist of a pipeline 12 inches in diameter, one metering facility at the pipeline origin and terminus/custody transfer point, one pig launcher, one pig receiver, cathodic protection system, two main block valves and two additional emergency shutdown valves, as specified by the California State Fire Marshal.

The carbon dioxide will be delivered to the custody transfer point for injection into deep underground hydrocarbon reservoirs for CO_2 EOR and sequestration.

Pursuant to U.S. Department of Transportation (DOT) regulations, the Project conducted a risk assessment for the carbon dioxide pipeline. Appendix E, Carbon Dioxide Technical Report, presents the results of the required Risk Assessment.

2.4.7 Heat Rejection Systems

Waste heat (i.e., low-grade thermal energy that is impractical to recover and reuse) from the Project will be rejected to the atmosphere. Two types of heat rejection systems are used, depending on the process requirements. Air coolers (fin-fan exchangers) are used for direct heat rejection to the atmosphere where low process outlet temperatures are not critical to efficiency. Mechanical draft cooling towers are used where indirect heat rejection is required or where low process outlet temperatures are critical to overall plant efficiency.

Air coolers are dedicated to specific services primarily within the Shift/LTGC, TGTU, and SWS units. Mechanical draft cooling towers serve multiple heat loads in more than one process unit. The Project has three mechanical draft cooling towers that are described below. Figure 2-31, Flow Diagram: Cooling Water System, shows the power block cooling water system. The configuration shown in this figure is similar to the ASU and gasification cooling towers.

2.4.7.1 Power Block Cooling Tower

The largest heat rejection load in the Project is the steam turbine surface condenser in the combined cycle power block. The main cooling water pumps supply water from the cooling tower basin and pump it through the surface condenser tubes and back to the top of the cooling tower cells. The return water flows into distribution piping below high-efficiency drift eliminators and above the cooling tower fill material. Electric motor-driven induced-draft fans

[3] Super-critical refers to a material at a temperature and pressure above its critical point. At these conditions there is no defined phase difference between liquid and vapor.

move air up through the tower fill material, contacting the cooling water with air and promoting evaporative cooling. A separate set of auxiliary cooling pumps supply water from the cooling tower basin and pump it through plate type closed cooling water (CCW) exchangers and return the water to the cooling tower fill material. The CCW pumps circulate higher purity water through the CCW exchangers that cool the water before it removes heat from the closed-circuit cooling water users. The closed-circuit cooling water users include the CTG and STG generator coolers and lube oil coolers. The use of a separate closed cooling water system also reduces the electric power load by enabling the shutdown of the large, main circulating pumps when the power block is in standby, ready to start, or following an STG shutdown.

A chemical feed system will supply water conditioning chemicals to the circulating water to minimize corrosion and control the formation of mineral scale and biofouling. Sulfuric acid will be fed into the circulating water system for alkalinity reduction to control the tendency for scaling. The acid feed system will consist of storage and two full-capacity metering pumps. A polyacrylate solution is also fed into the circulating water system as a sequestering agent to further inhibit scale formation. This system also requires storage and two full-capacity metering pumps. Sodium hypochlorite is added to prevent biofouling in the circulating water system. The system requires storage and two full-capacity metering pumps.

The total circulation rate for the power block cooling tower is approximately 175,000 gpm. The cooling tower is provided with high-efficiency drift eliminators designed to reduce drift to less than 0.0005 percent of the circulating water flow rate.

2.4.7.2 Gasification Block Cooling Tower

The Gasification Block cooling water system design is similar to the power block, only substantially lower duty. The major heat rejection duties are from the carbon dioxide compressor and the AGR refrigeration unit. Cooling water is also supplied to the gasification, Shift/LTGC, SRU, TGTU, SWS units and other miscellaneous users. Compressor lube oil systems, large motor cooling, and other services that require higher purity cooling water are supplied by the closed-circuit cooling water loop. The Gasification Block cooling tower has a cooling water basin, pumps, and piping system with a circulation rate of about 48,000 gpm. The tower is supplied with high-efficiency drift eliminators designed to reduce drift to less than 0.0005 percent of circulation.

2.4.7.3 Air Separation Unit Cooling Tower

The ASU cooling water system design is also similar to the power block and the duty is also substantially lower. The major heat rejection duties are from the main air compressor intercooler and aftercooler, the booster air compressor intercooler, and the nitrogen compressor intercooler. Compressor lube oil systems, large motor cooling, and other services that require higher purity cooling water are supplied by the closed-circuit cooling water loop, which rejects heat to the ASU cooling tower. The ASU cooling tower is located in the ASU unit near the cooling loads. The ASU cooling tower has separate pumps and piping systems and is operated independently of the other cooling water systems. The ASU cooling tower circulation rate is about 43,000 gpm and the tower is supplied with high-efficiency drift eliminators designed to reduce drift to less than 0.0005 percent of circulation.

2.4.8 Auxiliary Boiler

The auxiliary boiler is a pre-engineered package boiler that will provide steam for pre-startup equipment warm-up and for other miscellaneous purposes when steam from the gasification process or HRSG is not available. During normal operation, the auxiliary boiler may be kept in warm standby (steam sparged, no firing) or cold standby (no sparging), and will not have emissions. The boiler will produce a maximum of about 100,000 pounds per hour of steam and will be fueled only by pipeline natural gas. The boiler will be equipped with low nitrogen oxide burners and flue gas recirculation to minimize emissions.

2.4.9 Flares

Although the Project is designed to avoid flaring during steady state operations, flares are needed to protect the Project operators and equipment. The Project employs three pressure relief systems and their corresponding flares (Gasification, Rectisol, and SRU) for this purpose. All three flares are conventional pipe flares. The Rectisol and SRU flares are provided with natural gas assist. Vessels, towers, heat exchangers, and other equipment are connected to piping systems that will discharge gases and vapors to a relief system in order to prevent excessive pressure from building up in the equipment and to allow safe venting of equipment during routine startup, shutdown, or emergency operations.

During normal, non-startup plant operation the three flares will be operated in a standby mode with only “de minimis” emissions from the natural gas pilot flames. As explained below, two of the flares will be also be used to occasionally dispose of excess startup gases in a safe manner.

2.4.9.1 Gasification Flare

The Gasification Block will be provided with a relief system and associated gasification flare to safely dispose of gas streams during gasifier startup, shutdown, and unplanned upsets or emergency events; syngas during AGR startup; hydrogen-rich gas during short-term emergency combustion turbine outages; or other various streams within the Project during other unplanned upsets or equipment failures. The power block, shift, and Gasification Unit vents are collected in a HP flare header. A simplified process flow sketch of the gasification flare system is shown in Figure 2-32, Flow Diagram: Gasification and Rectisol Flare Systems.

Reduced-pressure sour gas vents from the gasification and shift units during shutdown depressurizing operations are first scrubbed in the gasification amine absorber to remove essentially all the sour sulfur compounds and then fed to an LP flare header. Both the HP and LP flare headers are routed to a common flare knockout drum to remove condensed moisture and any potentially entrained liquids.

2.4.9.2 Sulfur Recovery Unit Flare

An SRU flare will be used to safely dispose of gas streams containing sulfur during startup and shutdown (as described further in this section) and gas streams containing sulfur during unplanned upsets or emergency events. Acid gas derived from the AGR, Gasification Unit, and SWS overhead is normally routed to the SRU for recovery as elemental sulfur. During cold plant startup of the gasifiers, AGR, and Shift units, these acid-gas streams will be diverted to the SRU flare header for a short time. To reduce the emissions of sulfur compounds to the environment during SRU or TGTU shutdown, the acid gas is routed to the emergency caustic scrubber, where the sulfur compounds are absorbed with caustic solution. After scrubbing, the gas is then routed to the elevated SRU flare stack via the SRU flare knockout drum. Fresh and spent caustic tanks and pumps are provided to allow delivery of fresh caustic and disposal of spent caustic. A simplified process flow sketch of the SRU flare system is shown in Figure 2-33, Flow Diagram: SRU Flare System.

2.4.9.3 Rectisol Flare

A Rectisol Flare will be used to safely dispose of low-temperature gas streams during startup, shutdown, and unplanned upsets or emergency events. Cold reliefs and vents from the AGR Unit and its associated Refrigeration Unit are collected in the Rectisol flare header. The Rectisol flare header is used only in emergencies or upsets and contains gases that can be below the freezing point of water. For this reason, the Rectisol flare header gases are segregated from the wet gases in the gasification flare header. A simplified process flow sketch of the Rectisol flare system is shown in Figure 2-32, Flow Diagram Gasification and Rectisol Flare Systems.

2.4.10 Emergency Engines

The following is a description of the emergency engines required for the Project. These engines will be fueled using ultra-low sulfur diesel fuel.

2.4.10.1 Diesel Generator

Two 480-V, 60 Hz, 3-Phase, 2,000-kW, 0.8-PF standby diesel generator(s) in an outdoor enclosure will be connected to the 480-V switchgear to supply emergency essential service power to critical lube oil and cooling pumps, gasification and auxiliary steam systems, gasification quench system, station battery chargers, UPS, heat tracing, control room, and emergency exit lighting, and other critical plant loads.

A Local Control Panel (LCP) will be located on base with standard microprocessor–based engine and generator controls, interlocks, metering, alarms, and synchronizing system. Remote control of the diesel generator shall be from DCS operators via a fiber optic cable to Sellers control system.

2.4.10.2 Emergency Diesel Firewater Pump

One approximately 600-horsepower (hp), 415-kW standby firewater pump will be located adjacent to the firewater tank.

2.4.11 Fire Protection

2.4.11.1 Fire Protection Program

The Project Fire Protection Program includes both fire prevention and protection measures. Employment of conservative equipment layouts, segregation of critical components, and the remote location of non-essential resources are the backbone of the fire mitigation/suppression measures employed.

Conservative equipment spacing and segregation of potentially hazardous activities from the balance of the Project are the guiding principles employed to protect personnel and property. The extensive use of temperature detectors in the gasification area provides the capability to monitor the equipment and annunciate early warnings of abnormal excursions. Flammable gas monitors will be strategically located in the Project Site to detect and alarm hazardous levels. Oil containment sumps and fire walls will be erected to isolate large transformers from adjacent facilities. Structural steel will be protected with fire-proofing materials in strategic areas. Process liquid drains will be configured to contain liquid spills within the unit of origin. Grading and paving plans will be prepared to complement this objective. An extensive plant grounding system will be installed to dissipate static electrical charges. Emergency lighting is provided to illuminate egress lanes.

Fire suppression will be provided by various means. A dedicated fire water storage and site-wide loop distribution system, including automatic fire suppression (deluge/mist), and manual fire water fighting equipment (monitors and hydrants), will be provided. Inert gas suppression systems will be installed in areas where water systems would otherwise cause damage to plant equipment. Carbon dioxide fire suppression systems will be provided in the combustion turbine enclosures. Provisions for the deployment of aqueous fire fighting foam (AFFF) will be included with the methanol storage tanks. Steam is used to smother fires originating in hot equipment that may otherwise be further damaged by the application of relatively cold fire water.

The degree and extent of fire protection and suppression systems provided will be in complete compliance with applicable city, state, and national codes; insurer requirements; and industry standards.

The Project Site is subdivided into discrete fire areas to identify potential hazards, protect personnel, control a fire incident within a defined area, limit the spread of fire to other areas, and to minimize the possibility of consequential fire damage in other areas of the Project. Fire area boundaries are based on:

- The type, quantity, density, and locations of each fire hazard (solid, liquid, and gas)
- Location and configuration of critical plant equipment
- Consequence of damage to plant equipment
- Location of fire detection alarm panels, fire water storage, and pumping systems

The Project Fire Protection System design is based on the single risk area concept. This considers that only one fire will occur in any one of the identified fire areas at any given time. The major hazard identified in the material handling area is dust from the petcoke conveying, storage, and sizing operations. The primary hazards in the gasification area are the syngas and hydrogen-rich fuel intermediate streams. Multiple hazards are present in the power block, including natural gas and hydrogen-rich gas, hydrogen generator coolant, ammonia for emissions control, and the hydrocarbons contained in the lube/seal oil systems. The methanol system and storage represents an additional risk in the AGR area. Toxic and potentially flammable sulfur compounds are present in the AGR and the SRU. The capacity of the fire water storage, supply, and distribution system described below was sized based on the demand of the largest fire risk area.

The following provides an overview of the salient points of the Project's plan for fire detection and suppression.

2.4.11.2 Firewater Storage and Distribution System

The Firewater Distribution System is shown in Figure 2-34, Flow Diagram: Fire Water System and includes the following equipment:

- Firewater Storage Tank (~ 3 million gallons)
- Firewater Pump (Electric Motor) (6,000 gpm)
- Firewater Pump (Diesel Motor) (6,000 gpm)
- Jockey Pump
- Fire water ring header, laterals, hydrants and monitors

2.4.11.3 Automatic Fire Suppression System

The Automatic Fire Detection Systems are intended to identify the presence of hazardous/toxic/inert dust, gases, abnormal heat, and/or smoke. In the event that a hazardous situation is detected within any one of the designated fire areas, an alarm will sound, strobe lights will flash, and the applicable suppression system will automatically be deployed. The primary Automatic Fire Suppression System will employ firewater as the fire-fighting media. The Control Room, Rack Room, and "under floor" areas will use inert gas suppression systems. The type of inert gas and deployment method will be selected to minimize personnel exposure and plant equipment damage. The Gas Turbine enclosures will be flooded with carbon dioxide to displace oxygen to suppress any incident identified therein. Wherever an inert gas is used for fire suppression, a pre-release alarm will sound to inform any personnel working in the area to leave immediately. The meaning of these pre-alarms (tone, duration, etc,) and the time allotted for personnel to leave an area will be stressed during each unit's pre-entry training session.

An Automatic Fire Suppression System is planned to be employed at the following locations:

Deluge Spray Systems

- Gas Turbine Main Transformers
- Gas Turbine Isolation Transformers
- Steam Turbine Main Transformers
- Steam Turbine Lube Oil Equipment
- Auxiliary Simple Cycle Gas Turbine Main Transformer

- Main Air Compressor Lube Oil Equipment
- Booster Air Compressor Lube Oil Equipment
- AGR Methanol Systems
- Aqueous Ammonia Storage Facility
- Gasification Structure

Pre-Action Water Spray Systems

- STG Bearing Area
- STG Pedestal Area
- Turbomachinery Lubrication Systems (air, nitrogen, carbon dioxide)
- AGR Methanol System

2.4.12 Plant and Instrument Air

Utility and instrument air for the entire plant will normally be supplied by taking a relatively small slip stream of compressed air from the ASU. Backup air will be provided by an air compressor/dryer skid located in the power block.

Primary plant service and instrument air will be extracted from the ASU air compression equipment and cooled. This air will be clean and dry, and will be directly fed to the plant and instrument (P&I) air distribution system without further conditioning.

Secondary backup P&I air will be supplied from a stand-alone package air compressor/dryer/ accumulator skid. The quality and quantity of air provided from this source will be similar to that of the primary air system.

Both primary and secondary air sources will be piped to the plant-wide distribution systems. The instrument air piping distribution system is sized to ensure that adequate quantities are supplied to the various instrument and control air consumers. Accumulators/volume bottles will be installed nearby large intermittent air consumers (i.e., fast-acting control valves) to make certain that the required response times are attained.

Project service air system utility stations are positioned throughout the facility to provide plant air for housekeeping and maintenance activities. The source of the air to these utility air users will be automatically shut off on low air pressure. This feature will ensure that priority is given to the instrument air system to make certain that adequate volumes are available to safely operate and control the facility.

2.4.13 Emission Monitoring Systems

CEMS will be installed on several stack emission sources as required by applicable regulations and permit conditions. These analyzers will be designed, installed, certified, and calibrated in accordance with applicable LORS. In general, it is expected that these systems will sample, analyze, and record stack emission data for several specified pollutants. CEMS will incorporate data handling and acquisition systems to automatically generate emissions data logs and compliance documentation. Alarms will alert operators if stack emissions exceed specified limits.

Each CEMS system will undergo periodic calibration, audits, and testing to verify accuracy. It is anticipated that the following CEMS systems will be required for the indicated emissions:

- HRSG – nitrogen oxide, carbon monoxide, and oxygen
- Auxiliary CTG – nitrogen oxide, carbon monoxide, and oxygen
- Tail Gas Thermal Oxidizer – sulfur dioxide and oxygen
- Hydrogen-Rich Fuel – Total sulfur

In addition to continuous monitoring, the Project will perform periodic stack emission tests to verify compliance as required.

2.4.14 Hazardous Material Management

A variety of hazardous reagents and materials will be stored and used at the Project in conjunction with construction, operation, and maintenance (O&M) of the Project. In general, the type and character of these materials will be the same as those for other IGCC projects.

Hazardous materials used during the construction of the Project would mainly be limited to fuels and construction materials, including:

- Gasoline, diesel fuel, and motor oil for construction equipment
- Compressed gas cylinders containing oxygen, acetylene, and argon for welding
- Paint and cleaning solvents
- Concrete form release
- Miscellaneous lubricants, adhesives, and sealants

Each construction contractor will be responsible for maintaining a set of Material Safety Data Sheets (MSDSs) for each on-site chemical they control and construction workers will be made aware of their location and content.

The most likely accidents involving hazardous materials during construction might occur from small-scale spills during cleaning or use of other materials in the storage areas or during refueling of equipment. Such spills will be immediately cleaned up and materials containing hazardous substances will be properly disposed in accordance with applicable LORS.

Hazardous materials that may be routinely stored in bulk and used in conjunction with the Project operations include, but are not limited to, methanol, petroleum products, flammable and/or compressed gases, acids and caustics, aqueous ammonia, water treatment and cleaning chemicals, paints, and some solvents. Table 2-17, Hazardous Materials Usage and Storage During Operations Based on Title 22 Hazardous Characterization, and Table 2-18, Hazardous Materials Usage and Storage During Operations Based on Material Properties, lists each material and describes the approximate annual quantity needed and use of the material during operations.

Figure 2-35, Preliminary Hazardous Material Location Plan, shows the location of major sources of hazardous materials on the Project Site.

Table 2-17
Hazardous Materials Usage and Storage During Operations
Based on Title 22 Hazardous Characterization[1]

Material	Hazardous Characteristics[2]	Purpose	Storage Location	Maximum Quantity Stored	Storage Type
Sodium Hydroxide	Corrosivity	Plant Wastewater ZLD, Sour Water Treatment, Gasification, Caustic Scrubber	Outdoors	60,000 gallons (5 to 50 wt% NaOH)	Carbon steel AST with secondary containment
Molten Sulfur	Ignitability, Reactivity	By-product for sale	Outdoors	150,000 gallons	Two sulfur pits constructed of compatible material
Methanol	Ignitability	Gasifier startup-fuel AGR solvent make-up	Outdoors	550,000 gallons	1 × 300,000-gallon AST with secondary containment + 250,000-gallon contained in process vessels of AGR
Compressed Gases (Ar, He, H_2)	Asphyxiant	Lab	Indoors	Minimal	Cylinders of various volumes
Chemical Reagents (acids/bases/—standards)	Corrosivity, Reactivity	Lab	Indoor chemical storage	<5 gallons	Small original containers
Flammable/Hazardous Gases (H_2, CO, H_2S) Syngas and Hydrogen-Rich Gas	Ignitability, Toxicity	Primary power generation fuel	Process piping/ vessels	In process quantities only, no storage on site	None
Miscellaneous Industrial Gases – Acetylene, Oxygen, Other Welding Gases, analyzer calibration gases	Ignitability, Toxicity	Maintenance Welding/ Instrumentation Calibration	Gas cylinder storage in Shop/ instrument shelters	Minimal	Cylinders of various volumes
Natural Gas	Ignitability	Startup/Backup/ Auxiliary Fuel	Supply piping only	Utility supply on demand via pipeline	None
Diesel Fuel	Ignitability	Emergency generator/fire water pump fuel	Outdoors	2,000 gallons	ASTs with secondary containment
Aqueous Ammonia	Reactivity, Toxicity	Emissions control (SCR), Gasifier pH control	Outdoors	20,000 gallons (19 wt%)	Pressurized horizontal AST within a secondary containment berm, filled with HDPE poly balls (floating cover).
Sulfuric Acid	Corrosivity, Reactivity, Toxicity	Plant Wastewater ZLD	Outdoors	2,000 gallons	AST with secondary containment

Table 2-17
Hazardous Materials Usage and Storage During Operations
Based on Title 22 Hazardous Characterization[1] (Continued)

Material	Hazardous Characteristics[2]	Purpose	Storage Location	Maximum Quantity Stored	Storage Type
Sulfuric Acid	Corrosivity, Reactivity, Toxicity	Cooling water, boiler feed water pH control	Outdoors	12,000 gallons	AST with secondary containment
Paint, Thinners Solvents, Adhesives, etc.	Ignitability, Toxicity	Shop / Warehouse	Indoor chemical storage area	<20 gallons	Small original containers
Boiler Feedwater Chemicals (e.g., Carbonic Dihydrazide, Morpholine, Cyclohexamine, Sodium Sulfite)	Corrosivity	Boiler feedwater pH/corrosion / dissolved oxygen/biocide control	Outdoor chemical storage area	<500 gallons	Small original containers
Hydrogen	Ignitability	STG & CTG generator cooling	Outdoor	29,000 standard cubic feet	Pressurized multi-tube trailer
CTG and HRSG Cleaning Chemicals (e.g., HCl, Citric Acid, EDTA Chelant, Sodium Nitrate)	Toxic, Reactive	HRSG Chemical Cleaning	Stored off site or temporarily on site	Intermittent cleaning requirement/ temporary storage only	Small original containers

Source: HECA Project.

Notes:
[1] All numbers are approximate.
[2] Hazardous characteristics identified per California Code of Regulations Title 22 §§ 66261.20 *et seq*., for hazardous wastes.

%	=	percent
<	=	less than
AGR	=	acid gas removal
Ar	=	argon
AST	=	aboveground storage tank
BFW	=	boiler feed water
CO	=	carbon monoxide
CTG	=	combustion turbine generator
CCW	=	closed cooling water system
EDTA	=	ethylene diamine tetra-acetic acid
H_2	=	hydrogen
H_2S	=	hydrogen sulfide
HCl	=	hydrochloric acid
He	=	helium
HRSG	=	heat recovery steam generator
HDPE	=	high density polyethylene
SCR	=	selective catalytic reduction
NaOH	=	sodium hydroxide
NO_x	=	nitrogen oxide
SO_2	=	sulfur dioxide
SRU	=	sulfur recovery unit
STG	=	steam turbine generator
TGTU	=	tail gas treating unit
ZLD	=	zero liquid discharge

Table 2-18
Hazardous Materials Usage and Storage During Operations
Based on Material Properties[1]

Material	Potential Hazardous Characteristics[2]	Purpose	Storage Location	Maximum Quantity Stored	Storage Type
Methyldiethanol amine	Mild Irritant, Mildly Toxic	Solvent for sulfur removal	Tail Gas Treating Unit (TGTU) – in process inventory plus outdoor storage	220,000 pounds (40 wt % solution)	Contained in process vessels of TGTU, AST
Sodium Hypochlorite	Corrosivity, Reactivity	Raw Water Treatment & Cooling tower biological control	Outdoor	7,000 gallons	Polyethylene ASTs with secondary containment
Ammonium Lignosulfonate	Mild Irritant	Slurry Prep Bldg for maintaining % solids in slurry	Indoor	63,000 gallons	ASTs with secondary containment
Combustion Turbine Wash Chemicals (specialty detergents and surfactants)	Toxic, Irritants	Combustion Turbine Cleaning	Chemicals are contractor provided and are either not stored on site or are stored only temporarily in a chemical storage area.	Intermittent use/cleaning by contractor	Small original containers
Water Treatment Chemicals	Irritant, Mildly Toxic	Raw water, demineralized water, and cooling water treatment	Indoor chemical storage area	<500 gallons	Drums or ASTs
Oxygen (95%), liquid	Oxidizer	Gasification, SRU	Outdoor	1,200 tons	AST within the ASU
Nitrogen[3]	Asphyxiant	Syngas fuel diluent for NO_x control, inert gas	Outdoor	50 tons	AST within the ASU
Cooling Water Chemical Additives (e.g., Magnesium Nitrate, Magnesium Chloride)	Mild Irritant, Mildly Toxic	Corrosion inhibitor/biocides	Outdoor chemical storage area near each cooling tower	<500 gallons	Small quantities in original containers
Diethylene glycol monobutyl ether (industrial cleaner)	Basic Compound, Toxic, Mild Irritant	Routine cleaning, degreasing, oxygen pipeline cleaning	Indoor	None	Temporary storage as needed provided by contractor

Table 2-18
Hazardous Materials Usage and Storage During Operations
Based on Material Properties[1] (Continued)

Material	Potential Hazardous Characteristics[2]	Purpose	Storage Location	Maximum Quantity Stored	Storage Type
Compressed Carbon Dioxide Gas[3]	Asphyxiant	Generator purging and fire protection	Outdoor	50,000 standard cubic feet for purging	Carbon dioxide, for fire suppression, stored in pressurized cylinders or tank
Propylene Glycol	Mild Irritant	Heat transfer fluid	Closed Loop Cooling System	<300 gallons (100 vol. % solution)	4 x ~55 gallon drum or ASTs
Propylene Glycol	Mild Irritant	Heat transfer fluid	Closed Loop Cooling System In process inventory	25,000 gallons (45 vol. % solution)	Contained in process equipment
Sodium Bisulfite	Irritant, Mildly Toxic	Raw water treatment	Indoor chemical storage area	<500 gallons	Drums or ASTs
Sodium Phosphate	Irritant, Mildly Toxic	Raw water treatment, Gasification, Plant Wastewater ZLD	Indoor chemical storage area	1,500 gallons	AST with secondary containment

Notes:
1 All numbers are approximate.
2 Potential hazardous characteristics based on material properties and potential health hazards associated with those properties.
3 Nitrogen and carbon dioxide are not hazardous materials but may be asphyxiants under some circumstances.

% = percent
< = less than
AGR = acid gas removal
Ar = argon
AST = aboveground storage tank
BFW = boiler feed water
CO = carbon monoxide
CTG = combustion turbine generator
CCW = closed cooling water system
EDTA = ethylene diamine tetra-acetic acid
H_2 = hydrogen
H_2S = hydrogen sulfide
HCl = hydrochloric acid
He = helium
HRSG = heat recovery steam generator
HDPE = high density polyethylene
SCR = selective catalytic reduction
NaOH = sodium hydroxide
NO_x = nitrogen oxide
SO_2 = sulfur dioxide
SRU = sulfur recovery unit
STG = steam turbine generator
TGTU = tail gas treating unit
ZLD = zero liquid discharge

The storage, handling, and use of hazardous materials will be in accordance with applicable LORS. Storage will occur in appropriately designed storage areas. Bulk tanks will be provided with secondary containment to contain leaks or spills. Safety showers and eyewashes will be provided in appropriate chemical storage and use areas. Personnel who could potentially handle hazardous materials will be properly trained to perform their duties safely and to respond to emergency situations that may occur in the event of an accidental spill or release.

2.4.15 Hazardous Waste Management

Hazardous wastes will be generated in various quantities as a result of construction waste and operational waste.

Hazardous Construction Waste

The majority of hazardous waste generated during construction will consist of liquid waste such as waste oil from routine equipment maintenance, flushing and cleaning fluids, waste solvents, and waste paints or other material coatings. Additionally, some solid waste in the form of spent welding materials, oil filters, oily rags and absorbent, spent batteries, and empty hazardous material containers may also be generated.

Generally, construction contractors will employ practices consistent with the proper handling of all hazardous wastes in accordance with applicable LORS. This includes all licensing requirements, training of employees where required, accumulation limits and duration, and record keeping and reporting requirements. Wastes that are deemed hazardous will be collected in hazardous waste accumulation containers placed near the area of generation. After the end of each workday, the accumulation containers would be moved to the hazardous waste accumulation area, where hazardous wastes can be stored for up to 90 days after the date of generation. All hazardous wastes will be removed from the Project Site by a licensed hazardous waste management facility.

Table 2-19, Summary of Construction Waste Streams and Management Methods, lists the anticipated construction wastes which includes both hazardous and non-hazardous waste, and identifies the likely disposition of the waste.

Hazardous Operations Waste

Estimated operations waste streams are shown in Table 2-20, Summary of Operating Waste Streams and Management Methods. This table includes both hazardous and non-hazardous waste sources. Used catalysts, carbon filters, and ZLD solids will be characterized and disposed of in accordance with applicable LORS. Spent caustic will be treated off site to oxidize sulfides to sulfates, and will be disposed of as a non-hazardous material.

Chemical cleaning wastes may also be generated from the periodic cleaning of machinery and piping. Waste lubricants such as waste oil will be periodically generated during the operations and maintenance of the Project. Waste oil will be collected and stored in appropriate containers and recycled by an approved contractor.

Table 2-19
Summary of Construction Waste Streams and Management Methods[1]

Waste Stream	Waste Classification	Amount	Disposal Method
Used Lube Oils, Flushing Oils	Hazardous or Non-Hazardous	7 55-gallon drums per month	Recycle
Hydrotest Water (One time per commissioning, reuse as practical, test for hazardous characteristics)	Hazardous or Non-Hazardous	2.8 million gallons total	Characterize. Drain non-hazardous to the Detention Basin. Dispose of hazardous at a hazardous waste disposal facility.
Chemical Cleaning Wastes (Chelates, Mild Acids, TSP, and/or EDTA – During Commissioning)	Hazardous or Non-Hazardous Recyclable	525,000 gallons total	Hazardous or non-hazardous waste disposal facility.
Solvents, Used Oils, Paint, Adhesives, Oily Rags	Cal-Hazardous[2] Recyclable	160 gallons per month	Recycle or dispose of as hazardous waste.
Spent Welding Materials	Hazardous	260 pounds per month	Dispose at a hazardous waste landfill.
Used Oil Filters	Hazardous	100 pounds per month	Dispose at a hazardous waste landfill.
Fluorescent/Mercury Vapor Lamps	Hazardous Recyclable	50 units per year	Recycle
Misc. Oily Rags, Oil Absorbent	Non-Hazardous or Hazardous Recyclable	1 55-gallon drum per month	Recycle or dispose at a hazardous waste landfill.
Empty Hazardous Material Containers	Hazardous Recyclable	1 cubic yard per week	Recondition, recycle, or dispose at a hazardous waste landfill.
Used Lead/Acid and Alkaline Batteries	Hazardous Recyclable	1 ton per year	Recycle
Sanitary Waste from Workforce (Portable Chemical Toilets)	Non-Hazardous	390 gallons per day	Pump and dispose by sanitary waste contractor.
Site Clearing – Grubbing, Excavation of Non-Suitable Soils, Miscellaneous Debris	Non-Hazardous	Minimal	Reuse Soils or dispose at a non-hazardous waste landfill.
Scrap Materials, Debris, Trash (Wood, Metal, Plastic, Paper, Packing, Office Waste, etc.)	Non-Hazardous	40 cubic yards per week	Recycle or dispose at a hazardous waste landfill.

Source: HECA Project

Notes:
[1] All Numbers are estimates
[2] Under California regulations
CTG = combustion turbine generator
EDTA = ethylene diamine tetra-acetic acid
STG = steam turbine generator
TSP = trisodium phosphate

Table 2-20
Summary of Operating Waste Streams and Management Methods[1]

Waste Stream	Waste Classification	Anticipated Maximum Amount per year	Disposal Method
Spent Claus Sulfur Recovery Catalyst (Activated Alumina)	Non-Hazardous	7 tons	Dispose at a non-hazardous waste landfill.
Claus Catalyst Support Balls (Activated Alumina)	Non-Hazardous	3 tons	Recycle.
Spent Sour Shift Catalyst (Cobalt Molybdenum)	Non-Hazardous	67 tons	Send to reclaimer for metals recovery.
Spent Titania (TiO_2)	Non-Hazardous	2 tons	Send to reclaimer for metals recovery.
Spent Hydrogenation Catalyst (Cobalt Molybdenum)	Non-Hazardous	2 tons	Send to reclaimer for metals recovery.
Hydrogenation Catalyst Support Balls (Alumina Silicate)	Non-Hazardous	1 ton	Recycle.
Spent SCR Catalyst (Titanium, vanadium, tungsten, combustion contaminants, and inert ceramics)	Hazardous	1,600 cubic feet	Return to supplier to reclaim/dispose.
Spent CO/VOC oxidation catalyst (Noble metals, other inerts, and combustion contaminants)	Non-Hazardous	600 cubic feet	Send to reclaimer for noble metals recovery.
Amine Regenerator Carbon Filter TGTU (Activated Carbon)	Hazardous	26 tons	Stabilize and dispose at a hazardous waste landfill.
Spent Mercury Removal Carbon Beds (Impregnated activated carbon)	Hazardous	14 tons	Stabilize and dispose at a hazardous waste landfill.
Sour Water Carbon Filter (Activated Carbon)	Hazardous	48 tons	Stabilize and dispose at a hazardous waste landfill.
Process Wastewater ZLD Solids (Inorganic and organic salts)	May be Non-Hazardous or Hazardous	5,300 tons	Characterize and dispose at a non-hazardous or hazardous waste landfill.
Plant Wastewater ZLD Solids (Inorganic and organic salts)	May be Non-Hazardous or Hazardous	15,000 tons	Characterize and dispose at a non-hazardous or hazardous waste landfill.
Refractory Brick and Insulation	Anticipated Non-Hazardous	360 tons	Characterize and dispose at a non-hazardous or hazardous waste landfill.
MDEA Sludge TGTU	Hazardous	2,000 gallons	Dispose at an incinerator or hazardous waste landfill.

Table 2-20
Summary of Operating Waste Streams and Management Methods[1] (Continued)

Waste Stream	Waste Classification	Anticipated Maximum Amount per year	Disposal Method
Sour Water Sludge	Hazardous	30 tons	Dispose at an incinerator or hazardous waste landfill.
Amine Absorber Residues TGTU (Iron and salts)	Non-Hazardous	20 cubic yards	Dispose at a non-hazardous waste landfill.
Spent Caustic	Hazardous	400,000 gallons	Offsite treatment to oxidize sulfides to sulfates. Adjust pH and dispose as non-hazardous.
Spent Sulfuric Acid	Hazardous	14,000 gallons	Hazardous waste disposal facility. May need to adjust pH first and re-characterize.
Off-Line Combustion Turbine Wash Wastes (Detergents and residues)	Hazardous or Non-Hazardous	15,000 gallons	Characterize and dispose as non-hazardous or hazardous waste.
HRSG Wash Water (Infrequent) (Detergent, residues, neutralized acids)	Hazardous or Non-Hazardous	100,000 gallons	Characterize and dispose as non-hazardous or hazardous waste
Water Treatment Plant Sludge and Used Water Filter Media	Non-Hazardous	90 tons	Characterize and dispose as non-hazardous or hazardous waste.
Used Oil	Hazardous	8,000 gallons	Recycle. Expected to meet the regulatory exemption for used oil when recycled.
Spent Grease	Hazardous	16 55-gallon drums	Characterize and dispose as hazardous waste.
Miscellaneous Filters and Cartridges	Hazardous or Non-Hazardous	150 cubic yards	Characterize and dispose as non-hazardous or hazardous waste.
Miscellaneous Solvents	Hazardous	Two 55-gallon drums	Recycle or disposal as hazardous waste.
Flammable Lab Waste	Hazardous	Two 55-gallon drums	Characterize and dispose as hazardous waste.
Waste Paper and Cardboard	Non-Hazardous	320 cubic yards	Recycle.
Combined Industrial Waste (Used PPE, materials, small amounts of refractory, slurry debris, etc.)	Non-Hazardous	320 cubic yards	Dispose at a non-hazardous waste landfill.

Table 2-20
Summary of Operating Waste Streams and Management Methods[1] (Continued)

Waste Stream	Waste Classification	Anticipated Maximum Amount per year	Disposal Method
Gasification solids (Solid slag-like product)	Anticipated to be Non-Hazardous or covered by regulatory exclusion	51,000 to 274,000 short tons (wet); 25,500 to 137,000 short tons (dry)	Reuse, reclaim sellable metals, or characterize for landfill disposal in accordance with applicable LORS.

Source: HECA Project

Notes:
1 All numbers are estimates.
HRSG = heat recovery steam generator
MDEA = methyldiethanol amine
PPE = personal protective equipment
SCR = selective catalytic reduction
TGTU = tail gas treating unit
ZLD = zero liquid discharge

As with construction hazardous waste described above, where appropriate, hazardous waste resulting from operation activities will also be collected in hazardous waste accumulation containers placed near the area of generation. After the end of each workday, the accumulation containers will be moved to hazardous waste accumulation areas where hazardous wastes can be stored for up to 90 days after the date of generation. All hazardous wastes will be properly removed from the Project Site in accordance with applicable LORS.

2.4.16 Storm Water Management

Storm water management for the Project is designed to avoid direct discharge to surface waters. Clean storm water runoff from process areas will be routed to an on-site storm water retention basin before it is used as makeup water to the cooling towers. Potentially contaminated water will be tested to determine an appropriate destination for re-use. Depending on the water quality, it may be used for cooling tower makeup, used for gasifier slurry water makeup, or disposed in one of the ZLD systems. Project Site storm water runoff in non-process areas but within the main plant area will be routed to a lined retention basin. Retention basins and storm water collection/conveyance systems will be designed in accordance with the Kern County Development Standards. A preliminary site drainage plan is presented in Figure 2-36, Preliminary Storm Water Drainage Plan.

Storm water from non-process areas outside the main plant area but within the Project Site should be relatively clean. Runoff from these areas will be separately collected in retention basins located throughout the Project Site. The retention basin locations are also shown in Figure 2-36, Preliminary Storm Water Drainage Plan. Storm water generated at the Project Site will be managed as follows:

- Non-contact storm water runoff outside the power block and process areas will be routed to storm water retention basins. After solids have settled and water is determined to be suitable for reuse, storm water will be filtered for suspended solids removal before being used as cooling tower makeup water. If this collected storm water is determined to be unsuitable for cooling tower use, then it will be reused in the slurry preparation area or disposed of in one of the ZLD systems.

- Storm water that may be contaminated with oil will be separately collected and routed to an oil/water separator. Recovered waste oil from the separator will be disposed off site in accordance with applicable LORS. The separated water will be reused or disposed as described above.

- Runoff in the AGR Unit will be collected in a separate lined, dedicated AGR storm water retention basin. The AGR unit collection system is isolated to contain any potentially contaminated water that could result in the unlikely event of a methanol spill.

- Storm water runoff from chemical and oil storage areas will be held within the associated secondary containment. Storm water held in these areas will first be tested. If it is acceptable for cooling water makeup, then it will be routed to the retention pond. Oily storm water will be routed through an oil/water separator.

- Drainage within process areas where solids are present (e.g., coal, petcoke, fluxant, or gasifier solids) will be collected and conveyed to the solids handling water collection facility. The collection facility will be constructed of concrete, and will provide for mobile equipment access to remove accumulated solids. Water that accumulates within the solids handling collection facility will be reused as makeup to gasification or treated in process waste water ZLD.

- Drainage from remote solids handling areas such as feedstock truck unloading, inactive feedstock storage, active feedstock silos, and the crusher station will be collected in local area retention basins for settlement, testing, reuse, and/or treatment as appropriate.

A Storm Water Pollution Prevention Plan (SWPPP) will be developed prior to operations. The Project storm water runoff will be managed in accordance with this plan, which will include the measures outlined above.

2.4.17 Control System

The Project Control System will require the integration of many available technologies related to sensors, control elements and data acquisition and control (as shown on Figure 2-37, Control System Block Diagram). It is intended to assemble the total system so that the plant operations personnel will have the “state of the art” best control and monitoring capabilities available with modern technology. The Project will be designed around a DCS supported by auxiliary systems to allow personnel to analyze Project conditions and react timely to upset conditions within the shortest period of time. Multi-level system architecture will be provided with security levels between each level in order to prevent accidental manipulation of Project operations.

The overall design of the instrumentation and control systems will be in accordance with applicable national and local standards such as IEEE, National Fire Protection Association, and Instrument Society of America (ISA). Electrical equipment and components will also be purchased requiring third-party approvals from Underwriter’s Laboratories (UL), Factory Mutual Research Corporation (FM), or others Canadian Standards Association (CSA), as required.

2.4.18 Project Buildings

Essential buildings and kiosks will be provided on site to facilitate the hourly operating requirements. The Project will be established on a “stand alone” basis for certain key infrastructure items as shown by the Project components listed below. The buildings and kiosks located on the Project Site will likely include:

- Control room, administration, and laboratory
- Fire hall and emergency first dispatch center
- Power distribution centers
- Instrument and control kiosks
- Analyzer shelters/kiosks
- Maintenance and warehouse
- Guard houses

2.4.18.1 Security Systems

There are cameras within the plant for environmental monitoring, process safety, and security. A motorized operator will control the main gate. The main gate operator will include inputs from control room and receptionist switches, exit loop, and a local keypad or card reader station. An intercom system will be provided to allow voice communications between the main gate and the control room and receptionist area. The main gate intercom station will be near the local keypad or card reader.

2.5 PLANT OPERATING SCENARIOS AND EMISSIONS

2.5.1 Normal Operations

The Project will operate as a baseload low-carbon power generation facility using hydrogen-rich fuel. The Gasification Unit has three GE quench gasifiers: two are normally operating and one is a spare. This configuration will maximize the availability of hydrogen-rich fuel sufficient to baseload the GE Frame 7FB CTG. Depending on the gasifier feedstock, surplus hydrogen-rich fuel may be available for duct firing in the HRSG. If only one gasifier is operating, the GE Frame 7FB can be co-fired with natural gas. The allowable co-firing range is from 45 percent hydrogen-rich fuel to 90 percent hydrogen-rich fuel. The CTG can also operate on 100 percent hydrogen-rich fuel or 100 percent natural gas. The GE Frame 7FB CTG can operate across its emission compliance load range of 60 to 100 percent of baseload on either hydrogen-rich fuel or natural gas. The HRSG can be duct-fired on either surplus hydrogen-rich fuel or natural gas.

An auxiliary simple cycle CTG (GE LMS100®) is provided to supply plant power when the combined cycle block is not available. The simple cycle CTG is designed to operate independently from the rest of the facility and can be used to supply additional export peaking power when needed. The auxiliary simple cycle CTG requires high-pressure natural gas and the natural gas compressor will be operated whenever the auxiliary simple cycle CTG is operated.

Table 2-21, Project Emissions Summary for Normal Operations, presents a summary of the steady state emissions and emission control devices associated with the normal operating modes discussed above. Figure 2-38, Preliminary Emissions Sources Plot Plan, identifies the emission sources on the Project Site plot plan. Figure 2-39, Block Flow Diagram with Air Emission Sources, shows the process sequence and emission points for the Project.

2.5.2 Startup

This section describes a “cold” startup. A cold startup assumes the plant was shut down for a period of time and is at ambient temperature. This sequence assumes that all the necessary utility and support systems are already in service (Project distributed control system, fire protection and other safety systems, electrical switchyard and in-plant electrical distribution, water treatment, process and plant wastewater ZLDs, natural gas, steam, instrument and power plant air, purge nitrogen, etc.).

The IGCC takes 4 to 6 days from cold start to export of low-carbon power. The following summarizes the startup sequences.

Table 2-21
Project Emissions Summary for Normal Operations (tons per year)

Pollutant	Total Annual	HRSG Stack Maximum[1]	Auxiliary CTG	Cooling Towers[2]	Auxiliary Boiler	Emergency Generators[3]	Fire Water Pump[4]	Gasification Flare	SRU Flare	Rectisol Flare	Tail Gas Thermal Oxidizer	CO_2 Vent	Gasifier Vents	Feedstock[5]
NO_X	203.8	167.2	17.4	--	1.7	0.2	0.1	4.3	0.2	0.2	10.9	--	1.8	--
CO	350.3	150.2	27.6	--	5.8	0.1	0.2	48.8	0.1	0.1	9.1	106.9	1.5	--
VOC	40.7	32.5	4.6	--	0.6	0.03	0.01	0.003	0.002	0.002	0.3	2.4	0.1	--
SO_2	42.2	29.2	3.8	--	0.3	0.001	0.0003	0.004	0.055	0.003	8.8	--	0.03	--
PM_{10}	149.3	99.7	20.6	24.1	0.8	0.01	0.001	0.007	0.004	0.004	0.4	--	0.1	3.6
$PM_{2.5}$ [6]	137.1	99.7	20.6	14.5	0.8	0.01	0.001	0.007	0.004	0.004	0.4	--	0.1	1.0
NH_3	100.0	75.9	24.1	--	--	--	--	--	--	--	--	--	--	--
H_2S	1.3	--	--	--	--	--	--	--	--	--	--	1.3	--	--

Source: HECA Project

Notes:
1 Total annual HRSG emissions represents the maximum emissions rate from a composite firing scenario (all three fuels)
2 Includes contributions from all three cooling towers
3 Includes contributions from both emergency generators
4 VOC emissions for fire pump engine are combined with NO_x
5 Feedstock emissions are shown as the contribution of all dust collection points
6 Where $PM_{10} = PM_{2.5}$ it is assumed all PM_{10} is $PM_{2.5}$

CO = carbon monoxide
CTG = combustion turbine generator
H_2S = hydrogen sulfide
HRSG = heat recovery system generator
NH_3 = ammonia
NO_X = nitrogen oxide
PM_{10} = particles less than 10 micrometers in diameter
$PM_{2.5}$ = particles less than 2.5 micrometers in diameter
SO_2 = sulfur dioxide
VOC = Volatile Organic Compound

Once all the startup permissives are met, the GE Frame 7FB start signal is given and the gas turbine generator is used as a motor to rotate the gas turbine and accelerate it until the operation is self sustaining (static start). The gas turbine compressor is first partially loaded to provide enough air flow and duration to purge the HRSG. Following the purge, natural gas is introduced into the CTG combustors and the gas turbine operation becomes self sustaining and the static start is discontinued. Natural gas is required to startup the combustion turbine. When the gas turbine reaches 3,600 revolutions per minute, or “full speed, no load,” it is synchronized with the electrical grid and the main breaker is closed. Shortly after the CTG is synchronized, it is loaded to a minimum or “spinning reserve” load. All the preceding steps are executed automatically by the CTG’s control computer system. At this point the HRSG begins warming up and rapidly begins to produce steam. The steam is initially vented to the atmosphere, and as pressure builds in the steam system, the atmospheric vents close and the steam flow is diverted to the surface condenser. Once dry superheated steam is available at the STG, the steam turbine startup sequence can be initiated. The steam turbine metal temperature determines how quickly the steam turbine can be loaded. The cold start sequence requires the CTG to operate at reduced load (below the emission compliance level) for up to 3 hours, based on manufacturer’s literature. During this time, the gas turbine load is slowly increased to match the steam temperature to the steam turbine metal temperature to heat the steam turbine while minimizing thermal stress. Once the gas turbine reaches the required load, steam is introduced to control nitrogen oxide formation. Once the SCR catalyst reaches the required temperature, ammonia injection is initiated and the HRSG stack emissions will fall to the required compliance levels. The CTG can then be loaded normally to baseload and the steam turbine will reach a load based on the available steam.

The ASU will require 3 to 4 days to start up and reach full capacity. Because the ASU operates at cryogenic conditions, the startup sequence includes an extensive cool down and drying period. During this time, the Main Air Compressor (MAC) and Booster Air Compressor (BAC) will be operated to provide the “auto refrigeration” necessary to cool and dry the ASU. Near the end of the startup sequence, the ASU will begin producing LOX and LIN. The LOX is stored to provide a backup oxygen supply to cover a compressor trip or other short ASU outage. The LIN storage is provided as a backup supply for the purge nitrogen system. Once the ASU is producing enough oxygen to operate at least one gasifier, the LOX pumping and vaporization system can be started to make high-pressure oxygen vapor available to the Gasification Unit.

The AGR Unit is assumed to be ready to start (purged with nitrogen and with startup methanol levels established in the circulating system). Methanol circulation is started and the refrigeration system is started to begin cooling the methanol to normal operating temperature (approximately minus 40°F). This sequence is expected to take about 2 days and will complete at about the same time that sufficient oxygen is available to start a gasifier.

The SRU includes two conventional Claus reactor trains. Operation of the second Claus reactor train is not required if only one gasifier is operating, or if both gasifiers are operating on low sulfur coal/petcoke blends. This sequence assumes that both trains will be needed and that the first train is started up along with the single TGTU. The SRU reactor furnace is refractory lined. After an extended outage, both the refractory and the SRU catalyst require a gradual heating program that will take about 3 days. The heating is provided by firing natural gas with air in the reaction furnace. The combustion products flow through the reactor furnace, catalyst beds and boilers to the tail gas thermal oxidizer. During the refractory dryout/cure period, the hydrogenation reactor in the TGTU will also be preheated. The hydrogenation reactor catalyst requires pre-sulfiding which will be timed to complete when the SRU is feed-ready and the first gasifier is feed-ready. At the end of this sequence the amine circulation in the TGTU will be established and operating conditions will be established.

The gasifier vessels are refractory lined and require about 1 to 2 days to heat up to the temperature that allows oxygen and the feedstock to be introduced. Natural gas will be burned in air inside the gasifier to provide heat during startup.

The shift reactors require warm up and pre-sulfiding before sour syngas (containing hydrogen sulfide) can be introduced. The shift reactor catalyst is heated by circulating hot nitrogen across the catalyst beds for about 2 days. The nitrogen is heated indirectly with a high-pressure steam heater. Once the catalyst is hot, a small amount of sulfur containing compound is added to the circulating nitrogen. The pre-sulfiding is completed when traces of sulfur are detected in the effluent of the second shift reactor. The shift reactors are then isolated hot and ready for feed.

The carbon dioxide compression system will be purged and ready to compress carbon dioxide. The carbon dioxide compressor startup sequence will be timed to coincide with the time the AGR is producing carbon dioxide in sufficient quantity to allow sustained operation of the carbon dioxide compressor.

When the gasifier refractory reaches operating temperature, and the gasifier system has been purged with nitrogen, the gasifier can be started by introducing oxygen and a sulfur-free feedstock, then switching to the petcoke and/or petcoke-coal blend feedstock. Produced raw syngas is sent to gasification flare until the system pressure and flow are stabilized. For normal startup, the syngas sent to flare is essentially sulfur-free. The second gasifier can be started up as described above.

Syngas is diverted through the shift reactors and low-temperature gas cooling sections and then to the AGR. The circulating solution in the AGR will begin absorbing the carbon dioxide in the syngas. Once the carbon dioxide concentration in the “rich” solution reaches the required level, the flash drums will begin separating carbon dioxide vapor. This carbon dioxide will be washed to remove any traces of methanol and vented to the atmosphere.

Once sufficient hydrogen-rich fuel production is available, the GE Frame 7FB can initiate a switch either to co-firing or to 100 percent hydrogen-rich fuel. At this point, the startup is complete and normal operation begins.

Note that if the IGCC is being restarted after a short outage, when the equipment is still close to operating conditions, the durations of each step will be much shorter than indicated in the previous description.

2.5.3 Transient Operations

The Project normally operates with the combined cycle unit baseloaded on hydrogen-rich fuel. Transient operations associated with combined cycle load following are limited to the transition periods required to move from one operating mode to another. The following subsections describe the primary operating modes and the transient operations associated with them, as well as outage scenarios that are likely during annual operation.

The gasifier reactors operate at severe conditions and the typical run length can be as short as 1 month. For planning purposes, the Project expects 12 gasifier shutdowns and startups per gasifier per year in total. A single gasifier shutdown and restart can normally be accomplished without shutdown or restart of the other process units. Most of these gasifier shutdowns are expected to be planned, based on on-line diagnostics and maintenance history. A single gasifier can be shut down and switched to the spare gasifier in a few hours assuming that the spare gasifier has been heated up to operating condition. If the spare gasifier is cold, then about 2 additional days of single gasifier operation will be required while the spare gasifier is preheated to operating temperature.

The GE Frame 7FB will automatically switch from hydrogen-rich fuel to natural gas on loss of hydrogen-rich fuel pressure. During normal operation there is a small excess of hydrogen-rich fuel production that is fired in the HRSG duct burners. This allows the amount of duct firing to vary with the normal variations in gasifier operation. When a single gasifier is shut down, the duct firing will stop and the GE Frame 7FB CTG will switch to the co-firing mode. The CTG will continue to operate at baseload co-firing natural gas and hydrogen-rich fuel until a second gasifier is brought on-line. When sufficient hydrogen-rich fuel is available, the CTG will switch to 100 percent hydrogen-rich fuel and hydrogen-rich duct firing can be restored. During single gasifier operation, additional power can be generated by duct-firing natural gas.

The combined cycle unit can also operate on 100 percent natural gas with, or without, natural gas duct firing.

Combined cycle unit outages can either be planned or unplanned. Normal planned outages will be timed to occur with scheduled maintenance outages of the rest of the Project. Unplanned combined cycle outages can occur for a variety of reasons. A CTG shutdown will result in an immediate surplus of hydrogen-rich fuel that will be sent to the gasification flare. The feed rate on the operating gasifiers can be reduced to minimum while the cause of the outage is being determined. If the combined cycle unit can be brought back online in a relatively short time, the Gasification Block will continue to operate until the power block is back online. The Gasification Block is defined as all the process units needed to produce on-spec hydrogen-rich fuel, carbon dioxide, and sulfur. If the combined cycle outage is expected to be long in duration, then the Gasification Block will be shut down.

The Gasification Block can operate for limited periods without the combined cycle block operating. The Gasification Block auxiliary loads will be supplied initially from the grid following a GE Frame 7FB trip. The auxiliary simple cycle CTG can be started and loaded rapidly to provide the Gasification Block auxiliary loads.

2.5.4 Commissioning

Construction is initially scheduled by area and major equipment erection. Later construction transitions to completion by system in order to support turnover to the commissioning team.

Commissioning is completed by system, with the utilities (fire protection, power, water, natural gas, steam, etc.) completed first. The major process units will be commissioned in a sequence that begins with the feed-producing units and ends with the product-producing units and systems.

The major Gasification Block units, including the ASU, consume substantial amounts of electrical power. The power block also needs to be highly reliable before commissioning on hydrogen-rich fuel begins. For these reasons, the power block will be commissioned about 6 months ahead of the Gasification Block. The commissioning for the project will require four distinct phases, which are described in the following sections.

2.5.4.1 Combined Cycle Unit Commissioning on Natural Gas

The combined cycle unit will be initially commissioned on natural gas. The GE Frame 7FB uses diffusion combustors with steam injection, rather than dry-low nitrogen oxide combustors, so the nitrogen oxide tuning procedure is the primary difference. The following list briefly describes the steps for commissioning on natural gas:

- First fire
- Green rotor run-in
- Support of steam blows
- Initial steam turbine roll
- Nitrogen oxide tuning with steam injection
- Water wash and simple cycle CTG performance and emissions testing
- Duct burner testing
- Installation of SCR and oxidation catalyst
- CEMS drift test and source testing
- Combined cycle functional testing
- Water wash and combined cycle performance testing and continuous operation test

2.5.4.2 Commissioning the Auxiliary Simple Cycle CTG on Natural Gas

The auxiliary simple cycle CTG (GE LMS100®) uses only natural gas and is provided with water injection for primary nitrogen oxide control. The following list briefly describes the steps for commissioning on natural gas:

- First fire
- Nitrogen oxide tuning with water injection
- Installation of SCR and oxidation catalyst
- CEMS drift test and source testing
- Water wash and performance and functional testing

2.5.4.3 Gasification Block and Balance of Plant Commissioning

The following description includes the activities that are expected to have air emissions. The description assumes that the major utility support systems are already operational (power distribution, firewater, power plant and instrument air, water treatment, steam, boiler feedwater, etc.). The key activities and events are listed below:

- Auxiliary boiler initial firing and burner tuning
- Auxiliary boiler source testing
- Auxiliary boiler operation to support gasification commissioning (typically when the combined cycle block is not operating)
- Operation of the combined cycle block in support of Gasification Block commissioning
- Operation of the auxiliary simple cycle CTG in support of Gasification Block commissioning (typically when the combined cycle block is not operating)
- Cooling tower operation supporting the ASU, combined cycle block, and Gasification Block
- Gasification flare testing and operation in support of Gasification Block commissioning
- Rectisol flare testing and operation in support of AGR unit commissioning.
- SRU flare testing and operation in support of Gasification Block commissioning
- Gasifier testing and operation
- Testing and operation of the AGR, SRU, and TGTU
- Testing and operation of the carbon dioxide compression system

2.5.4.4 Combined Cycle Block Commissioning on Hydrogen-Rich Fuel

The combined cycle block will require additional testing and nitrogen oxide tuning with hydrogen-rich fuel. The testing will cover the range of natural gas/hydrogen-rich fuel blends and allowable load ranges. The combined cycle block is assumed to have been commissioned first on natural gas. The oxidation catalysts are assumed to be in service and active when the HRSG operating temperature is sufficient. The SCR catalyst and ammonia injection system are assumed to be operating whenever the SCR catalyst temperature is in the required range and operation is sufficiently stable. Ammonia injection may be off-line during the initial phases of nitrogen oxide tuning. The key activities and events that are expected to produce air emissions are listed below:

- Startup and shutdown of GE's Frame 7FB on natural gas
- Standby operation of the combined cycle block on natural gas
- CTG nitrogen oxide tuning on co-firing
- CTG nitrogen oxide tuning on 100 percent hydrogen-rich fuel
- CTG nitrogen oxide tuning on part load
- Water wash and performance testing on hydrogen-rich fuel
- Duct burner testing on hydrogen-rich fuel
- Source testing on hydrogen-rich fuel blends across the load range
- Functional testing including fuel transfers and load changes
- Plant wide performance test
- Plant wide operational reliability test

2.5.5 Plant Staffing

The operating staff will consist of management and engineers, shift supervision, and shift operating personnel. There will be five operating shifts with a shift supervisor and an operating/maintenance crew of approximately 10 people on each shift on a rotation basis. In addition to operation and management personnel, the Project will require qualified staffing in the following areas: production planning; equipment maintenance; instrument, electrical and control support; material coordinating/inventory/procurement; health/safety/security/environmental protection; administrative support; benefit/human relations; training; laboratory; and other necessary functions. It is estimated that the Project will employ approximately 100 full-time workers, with about 50 to 60 shift workers, and the rest day workers.

In addition to the permanent staff, there will be ongoing contract maintenance work for scheduled and un-scheduled outages. There are scheduled and unscheduled maintenance activities for the gasification system, and contract maintenance will be involved in the routine startup and shutdown of the gasifiers. The Gasification Block will also follow the gas turbine scheduled inspection maintenance cycle, typically on an annual basis. The contract maintenance will typically include inspections and overhauls for the large compressors and rotating machinery, the combustion turbine generators, electrical transmission equipment, the steam turbine and other steam generating boilers and heat exchangers, gasifier refractory repair and replacement, catalyst and sorbent change out, tower and vessel inspection, and repair/replacement of internals, as well as other non-routine maintenance.

2.5.6 Materials and Equipment Delivery During Operations

Table 2-22, Power Project Material Delivery, describes the delivery schedule and general, origination location of each product for the Project. The maximum number of material deliveries is approximately 200 per day. The total truck trips are estimated to be approximately 400 (which accounts for the delivery plus the return trip of the empty truck). Refer to Section 5.10, Traffic and Transportation, for additional details.

Table 2-22
Power Project Material Delivery

<table>
<tr><th>Product</th><th>Mode</th><th>Distribution Point</th><th>Maximum Delivery</th></tr>
<tr><td>Petcoke</td><td>Truck</td><td>Santa Barbara/Kern County/ Los Angeles County</td><td rowspan="2">180/day (petcoke plus coal)</td></tr>
<tr><td>Coal[1]</td><td>Truck</td><td>Kern County</td></tr>
<tr><td>Fluxant[2]</td><td>Truck</td><td>Various</td><td>9/day</td></tr>
<tr><td>Chemicals (e.g., methanol, aqueous ammonia, caustic, etc.)[2]</td><td>Truck</td><td>Various</td><td>10/day</td></tr>
</table>

Notes:
1 Will be transported by rail to transloading facility in Kern County.
2 Materials will be purchased in Kern County, as practical.

The following are the anticipated feedstock and fluxant delivery routes during operations:

- Petcoke and Fluxant Route – from I-5 to westbound Stockdale Highway, left turn on southbound Dairy Road (local road), left turn onto Adohr Road (local road), right turn into the Project Site and vice versa.

- Coal Route – from southbound Highway 43 to westbound Stockdale Highway, left turn on southbound Dairy Road (local road), left turn onto Adohr Road (local road), right turn into the Project Site and vice versa.

2.6 PROJECT CONSTRUCTION

The following section describes the construction process for the Project Site and linear facilities.

2.6.1 Project Site Construction

Construction activities for the Project will occur throughout the 37-month construction period. Figure 2-40, Preliminary Temporary Construction Facilities Plan shows the on-site construction areas, including laydown and parking. All construction laydown and parking areas will be located within the 473-acre Project Site. On-site construction activities include clearing and grubbing, grading, hauling, layout of equipment, delivery and handling of materials and supplies, and project construction and testing operations. The Project Site occurs in an area of relatively flat topography. Site grading will occur as necessary to form level building pads for major process units.

Construction site access will be via Dairy Road for truck deliveries and via Tupman Road for construction craft cars arriving and departing the site. Initial site preparation operations will include construction of temporary access roads, craft parking, laydown areas, office and warehouse facilities, installation of erosion control measures and other improvements necessary for construction,. Erosion control measures will include construction of storm water retention basins and related site drainage facilities to control runoff within the site boundary. Existing drainage patterns outside the site boundary will remain undisturbed. No runoff from outside the site boundary will flow onto the Project Site.

Figure 2-41, Preliminary Grading Plan, and Figure 2-42, Preliminary Paving Plan show the proposed grading and paving at the Project Site.

2.6.1.1 Construction Planning

The Engineering Procurement Construction (EPC) contractor will be responsible for the design, procurement, and construction of the Project. The EPC contractor will select subcontractors for certain specialty work as required. A separate EPC contractor may be used for the ASU.

2.6.1.2 Mobilization

The EPC contractor is expected to mobilize in approximately the fourth quarter of 2011. Project Site preparation work will include site grading and storm water/erosion control. Gravel and road base material will be used for temporary roads, laydown, parking, and work areas. Construction planning will include the evaluation of existing county roads. The roads will be upgraded as necessary to handle the increased loads and traffic.

2.6.1.3 Construction Offices, Parking, Warehouse, and Laydown Areas

Mobile trailers or similar suitable facilities (e.g., modular offices) will be used as construction offices for owner, contractor, and subcontractor personnel. All construction laydown and parking areas will be within the Project Site as shown in Figure 2-40, Preliminary Temporary Construction Facilities Plan.

Site access will be controlled for personnel and vehicles. A security fence will be installed around the Project Site boundary.

2.6.1.4 Emergency Facilities

Emergency services will be coordinated with the local fire department and hospital. An urgent care facility will be contacted to set up non-emergency physician referrals. First-aid kits will be provided around the Project Site and regularly maintained. At least one person trained in first aid will be part of construction staff upon mobilization. Additional personnel for environmental, health, and safety training, site security, and to provide appropriate levels of site first aid and medical support (nurse and/or medical practitioner) will be added as crew size increases. Fire extinguishers will be located throughout the site at strategic locations at all times during construction.

2.6.1.5 Construction Utilities and Site Services

During construction, temporary utilities will be provided for the construction offices, laydown area, and Project Site. Temporary construction power will be initially generator-powered and will transition to utility-furnished power. Area lighting will be strategically located for safety and security. Average construction water use is estimated to be about 10,000 gallons per day.

For construction activities, including hydrotesting of the process equipment and piping, maximum daily water usage of approximately 100,000 gallons is anticipated. The hydrotesting of the process equipment and other piping is normally done toward the end of project construction after the mechanical construction is complete. The hydrotest water will be sampled and tested. Clean water with suitable chemistry will be routed to the storm water retention basin. Water that is not suitable for routing to the retention basin will be transported by truck to an appropriately licensed off-site treatment or disposal facility.

The EPC contractor will provide the following site services:

- Environmental health and safety training
- Site security
- Site first aid
- Construction testing (Non-Destructive Examination [NDE], hydrotesting, Positive Material Identification [PMI], etc.)

- Site fire protection and fire extinguisher maintenance
- Furnishing and servicing of sanitary facilities
- Trash collection and disposal
- Disposal of hazardous materials and waste in accordance with LORS
- Erosion and dust control during construction activities
- Warehousing, mitigation management and logistics.

2.6.1.6 Construction Materials and Heavy Equipment Deliveries

Both rail and major freeway access are available in the vicinity of the Project Site. Construction materials such as concrete, structural steel, pipe, wire and cable, fuels, reinforcing steel, and small tools as well as consumables will be delivered to the Project Site by truck.

Major equipment such as the gasifier vessels, absorber vessels, shift converters, CTG, STG, transformers, elements of the HRSG, and other equipment will be delivered to the Project Site by special conveyance due to their weight and size.

Most equipment will be transported to the area via Interstate 5 or by rail. Rail deliveries will be off-loaded and transported by a specialized heavy-haul contractor near Buttonwillow and hauled to the Project Site. Large pieces of apparatus will be brought by barge to the Port of Stockton and delivered to the Project Site by a specialized heavy haul contractor.

2.6.1.7 Hazardous Materials Storage

Table 2-23, Hazardous Materials Usage and Storage During Construction Based on Title 22 Hazardous Characterization, and Table 2-24, Hazardous Materials Usage and Storage During Construction Based on Material Properties, lists each material and describes the approximate annual quantity needed and use of the material during construction. Hazardous materials generated during the construction period will be placed in properly identified and approved storage bins until they are recycled or disposed of off site in accordance with applicable LORS. Hazardous materials and commodities for use on site will be inventoried and appropriately stored. Warehouse personnel will maintain the records for these materials.

Non-hazardous refuse and construction rubbish will be sorted and stored in containers until removed from the Project Site for recycling or disposal.

2.6.1.8 Construction Disturbance Area

The majority of the Project Site is currently used for agricultural purposes. A small portion of an organic fertilizer-production facility is at the northwestern corner of the Project Site. Construction also consists of installation of off-site linear facilities, including process and potable water lines, a natural gas pipeline, a carbon dioxide pipeline, and a transmission line. Linear facilities are described in more detail in Section 2.6.1.10, below. The estimated acreages of land that will be used for construction of the Project are presented in Table 2-1, Project Disturbed Acreage.

Table 2-23
Hazardous Materials Usage and Storage During Construction
Based on Title 22 Hazardous Characterization[1]

Material	Hazardous Characteristics[2]	Purpose	Storage Location	Maximum Stored	Storage Type
Diesel Fuel	Ignitability, Toxicity	Refueling Construction Vehicles and Equipment	Laydown Area	2,000 gallons	Tank
Acetylene, Oxygen, Other Welding Gases	Ignitability	Maintenance Welding	Temporary Gas Cylinder Storage Area	2,000 standard cubic feet	Cylinders of various volumes
Lead/Acid and Alkaline batteries	Corrosivity, Toxicity	Power for Equipment	Warehouse/ shop area	<50 units	Unit
Paints, Solvents, Adhesives, etc.	Toxicity, Ignitability	Painting and Paint Removal, general construction activities	Temporary Chemical Storage Area	200 gallons/week	Drum
Gasoline	Ignitability, Toxicity	Refueling Construction Vehicles and Equipment	Warehouse/ Shop Area	2,000 gallons/week	Tank

Source: HECA Project.

Notes:
< = less than
[1] All numbers are approximate.
[2] Hazardous characteristics identified per California Code of Regulations Title 22 §§ 66261.20 *et seq*., for hazardous wastes.

Table 2-24
Hazardous Materials Usage and Storage During Construction
Based on Material Properties[1]

Material	Potential Hazardous Characteristics[2]	Purpose	Storage Location	Maximum Stored	Storage Type
Lubricating Oil	Mildly Toxic	Lubricating Equipment Parts	Laydown area	200 gallons	Tanks
Cleaning Chemicals/ Detergents	Toxic, Irritant	Periodic Cleaning	Contained in storage tanks on equipment skids	1,000 pounds	Tanks and containers or equipment

Source: HECA Project.

Notes:
[1] All numbers are approximate.
[2] Potential hazardous characteristics based on material properties.

2.6.1.9 Storm Water Runoff Prevention Plan

The Project Site erosion control will be accomplished during construction through the use of strategically placed berms, swales, and culverts to redirect runoff toward the storm water retention basins. Sand bags, filter bales, silt fences, and temporary dams will be installed to minimize the volume of sediment carried by storm runoff and to prevent the erosion of slopes and temporary drainage facilities. Grades will be designed to prevent the effects of ruts and ponding. Following each significant precipitation event, a site review of the effectiveness of the erosion control plan will take place. Storm water will be retained on site for impoundment in the storm water retention basins located as shown in Figure 2-40, Preliminary Temporary Construction Facilities Plan.

2.6.1.10 Linear Construction

The Project includes construction of the following off-site facilities, as shown on Figure 2-7, Project Location Map:

- Electrical Transmission Line
- Natural Gas Supply Pipeline
- Water Supply Pipelines
- Carbon Dioxide Pipeline

The section, township, and ranges intersected by the linears are shown on Figures 2-8, Project Location Details. The following provides details regarding the construction of the linear facilities.

Electrical Transmission Line

An electrical transmission line will interconnect the Project to Pacific Gas & Electric's (PG&E) Midway Substation. The transmission line will be constructed and owned by HEI up to the point of interconnect (Midway Substation). The power generated by the Project will be connected to the existing PG&E system by constructing a single tower, double-circuit, 230-kV transmission line. This double-circuit line will be connected to a new switchyard at the Project Site.

The Project is considering two alternative transmission routes, both of which extend from the west portion of the Project Site and continue north on the Dairy Road right-of-way and west on Adohr Road. Transmission Alternative 1 then continues north on Freeborn Road, turning northwest to the substation. Transmission Alternative 2 continues north along Dunford Avenue, turning northwest to the substation. Both alternatives are approximately 8 miles in length.

Approximately 60 steel poles are expected to be required for the electrical line interconnection. Construction of the interconnection line will consist of footing installations at 700-foot intervals, pole installation, insular and hardware installation, and pulling of conductor and shield wires. The new transmission line interconnection will be placed in an approximately 150-foot permanent right-of-way.

Construction of the new 230-kV transmission line interconnection will require approximately 6 months. It will be scheduled for completion and be operational in time for generation testing of the Project. Upgrades required within the PG&E Midway Substation will be performed by PG&E as required to accommodate the interconnection of the new transmission line to the Project Site.

Water Supply Lines

For process water, the Project will use brackish groundwater supplied from the BVWSD. BVWSD will construct and own the process water pipeline. The brackish water will be supplied from BVWSD's main trunk line, located in back of the West Side Drain and running roughly northwest to southeast from Seventh Standard Road to Tupman Bridge. The brackish water will be treated on site to meet all process and utility water requirements.

The process water pipeline route runs from Seventh Standard Road to the Project Site, along the existing BVWSD road on the north side of the West Side Canal. The process water supply pipeline will be approximately 15 miles in length.

In addition, BVWSD will construct and own a well field for the Project water supply that will be located in the western portion of BVWSD's service area near the West Side Canal in the vicinity of Seventh Standard Road, at the north end of the 15-mile-long process water line. It is currently anticipated that there will be up to five groundwater extraction wells. Two of these wells will provide operational redundancy. The maximum depth of the wells will be approximately 300 feet below ground surface.

For drinking and sanitary use, the Project will use potable water supplied by West Kern Water District. The potable water line will be constructed and owned by WKWD.

The potable water supply pipeline route begins near the intersection of SR 119 and Tupman Road and then continues northwest to the Project Site. The potable water line is approximately 7 miles in length. This pipeline will be placed in a parallel alignment with the natural gas pipeline over most of its route.

Horizontal Directional Drilling (HDD) will be used to install the pipeline under the Outlet Canal, the Kern River Flood Control Channel, and the California Aqueduct, as discussed further below. With the exception of these water crossings, water pipelines will be installed underground using cut and fill techniques. Installation of the water supply pipelines will involve typical construction activities, including trenching; hauling and stringing of pipe along the routes; welding; radiographic inspection and coating of pipe welds; lowering welded pipe into the trench; hydrostatic testing; and backfilling and restoring the approximate surface grade. Construction of the water pipelines is expected to take approximately 6 months to complete.

Natural Gas Supply Pipeline

A natural gas line will interconnect with PG&E or SoCalGas natural gas pipelines. The interconnect will consist of one tap off the existing natural gas line, one meter set, one service pipeline service connection, and a pressure limiting station located on the Project Site. The selected gas company will construct and own the natural gas pipeline.

The natural gas supply pipeline route will continue west along SR 119, turn north at Tupman Road, and then continue northwest to the Project Site. The natural gas line is approximately 8 miles in length. This pipeline will be placed in the same trench as the potable water pipeline for most of its alignment.

HDD will be used to install the pipeline under the Outlet Canal, the Kern River, the Kern River Flood Control Channel, and the California Aqueduct, as discussed further below. Construction of the natural gas pipeline interconnection will involve a variety of crews performing the following typical pipeline construction activities: hauling and stringing of the pipe along the route; welding, radiographic inspection, and coating of the pipe welds; trenching; lowering of the pipe into the trench; backfill of the trench; hydrostatic testing of the pipeline; tie-in to the existing pipeline, purging the pipeline; and cleanup and restoration of construction areas. Roads and rights-of-way will be restored to specifications of the Project and affected agencies.

Construction of the natural gas pipeline interconnection will take approximately 6 months. It will be scheduled to be finished and operational in time to provide test gas to the Project. Construction will occur in accordance with a traffic management plan to minimize impacts to traffic traveling on Tupman Road and SR 119.

Grade cuts will be restored to their original contours and affected areas will be restored to their original state so as to minimize erosion.

Carbon Dioxide Pipeline

The Project will include construction of a carbon dioxide pipeline to transfer the carbon dioxide captured during gasification from the Project Site to the custody transfer point. Carbon dioxide produced by the Project will be routed via this pipeline to the custody transfer point for injection into deep underground hydrocarbon reservoirs for CO_2 EOR and Sequestration. HEI will own and construct the pipeline between the Project Site and the custody transfer point. Oxy Elk Hills will construct and own the pipeline and transfer facilities downstream of the custody transfer point.

The Project is considering two alternative pipeline alignments. Each alignment extends from the southwestern corner of the Project Site. Alternative 1 crosses through Township 30 South, Range 24 East Sections 10, 9, 16, and 21, and ends in 28. Alternative 1 has two potential subroutes within Sections 21 and 28. Alternative 2 crosses through Sections 10, 16, 21, and 28. It has two potential subroutes within Sections 16, 21, and 28. Each alternative is approximately 4 miles in length.

HDD will be used to install the pipeline under the Westside Canal, the Kern River Flood Control Channel and the California Aqueduct, as discussed further below. With the exception of these crossings where the depth of the carbon dioxide pipeline may reach 100 feet below grade, the pipeline will be buried approximately 5 feet below grade to minimize the likelihood of third-party disturbance, and will be protected by cathodic protection and monitored by independent leak-detection systems. Construction of the carbon dioxide pipeline interconnection will involve a variety of crews performing the following typical pipeline construction activities: hauling and stringing of the pipe along the route; welding; radiographic inspection; coating of the pipe welds; trenching; lowering of the pipe into the trench; backfill of the trench; hydrostatic testing of the pipeline; purging the pipeline; and cleanup and restoration of construction areas. Grade cuts will be restored to their original contours and affected areas will be restored to their original state so as to minimize erosion.

Construction of the carbon dioxide pipeline will take approximately 6 months.

Pipeline Crossings and Horizontal Directional Drilling

The proposed routes of the above-described pipelines (shown on Figure 2-6, Project Location Map) illustrate that they cross county roads and/or one or more regional canals. The carbon dioxide, natural gas, and potable water pipelines will all be installed under the California Aqueduct, Kern River Flood Control Channel, and West Side/Outlet Canal using HDD, which minimizes direct impacts to the water courses and sensitive areas. The depth of HDD under the water bodies will comply with all applicable federal and state regulations.

The California Department of Water Resources (DWR) "Encroachment Permit Guidelines – June 2005" spells out specific requirements regarding the use HDD. The principal requirements include but are not limited to the following:

- A site-specific geotechnical report must be submitted to the DWR with the Encroachment Permit application
- Pipe sleeves are required with any pipeline carrying hazardous materials or pollutants
- The minimum separation between the bottom of the Aqueduct channel and the top of pipe is 25 feet.; further separation may be required depending on the actual pipe diameter
- Drawings submitted with the Encroachment Permit Application must include the following for buried pipelines (as a minimum):
  - Aqueduct mileposts at each crossing, pipe size, location, and type of material transported
  - Maximum operating pressure, type of pipe and pipe joints, pipe wall thickness, maximum test pressure, and description of test procedures
  - Type of sleeve/casing including diameter, joints, and wall thickness
  - Protection coatings and a description of control measures
  - Method employed to accommodate pipeline expansion and contraction
  - Thrust block location and details
  - Pipe line coatings and corrosion control measures
  - Location of shutoff valves on each side of the crossing
  - List of applicable design codes
  - Location, including depth of the buried aqueduct communication and control cables
  - Identification of existing utility easements or encroachments in the immediate vicinity of the proposed crossing

The HDD method includes a drilling rig that will bore a horizontal hole under the water crossings. The HDD could extend up to 1 mile, but much shorter distances are anticipated. At each of these crossings, a 100-foot by 200-foot laydown area (or entry/exit pit) has been identified on either side of the water course to accommodate the HDD installation (see Figure 2-8, Project Location Details).

Best management practices for HDD will include silt fencing around the drill sites, energy dissipation devices for discharging water from hydrostatic testing of the pipeline, selecting drilling fluids for environmental compatibility, and removing spent fluids from the areas immediately adjacent to the water bodies for safe disposal and to prevent contamination. In addition, soil erosion control measures will be implemented to prevent runoff and impacts to water quality.

2.6.2 Combined Construction Workforce

Construction is expected to begin in the latter part of the fourth quarter of 2011 and continue for 37 months. The schedule has been estimated on a single shift, 5-day basis, beginning at 6 a.m., Monday through Friday. Additional hours and/or a second shift may be necessary to make up weather delays, schedule deficiencies or to complete critical construction activities. During Project startup and testing, some activities may continue up to 24 hours per day, 7 days per week.

Most construction workers traveling to the Project Site from the south and east (e.g., Arvin, Taft, south Bakersfield) will reach Tupman Road from SR 119 and Interstate 5. Construction workers traveling to the Project Site from the north (e.g., Buttonwillow, Shafter, north Bakersfield) will reach the Project Site entrance at the intersection of Tupman Road and Station Road via Stockdale Highway and Interstate 5. Traffic management plans will be implemented for construction workers, shift changes, and hauling of oversize loads to the Project Site. Estimates of average and peak construction traffic during the on-site construction period, and traffic management for construction, are described in Section 5.10.4, Traffic and Transportation.

Table 2-25, Estimated Monthly Construction Workforce, shows the estimated construction labor by craft.

2.6.3 Combined Construction Equipment Requirements

Table 2-26, Construction Equipment Estimate, shows an estimate of construction equipment by type and by days of use per month.

2.6.4 Combined Construction Traffic

During the construction phase, there will be vehicular traffic both on and off of the Project Site. This includes traffic generated from the following activities:

- Delivery of heavy equipment to the Project Site, such as bulldozers and cranes
- Importation of construction fill material
- Delivery of structures, construction material, and equipment to the Project Site
- Daily commuting of construction workforce and managers
- Occasional visits from inspectors, officials, and regulators

General and heavy haul loads access to the Project Site will be from Stockdale Highway to Dairy Road to the Project Site. Regional access to the Project Site will be via Interstate 5, which runs north-south to the east of the Project Site, and SR 58, which runs east-west and is about 4 miles north of the Project Site. Direct access to the Project Site is provided by the following three routes:

- Construction Worker Route 1 – locally sourced or temporary workers lodging in Metropolitan Bakersfield and nearby communities via westbound Stockdale Highway, turn left on southbound Morris Road (local road), turn right on Station Road (local road), continuing across Tupman Road and into the Project Site.

Table 2-25
Hydrogen Energy California, Kern County Power Project
Estimated Monthly Construction Workforce

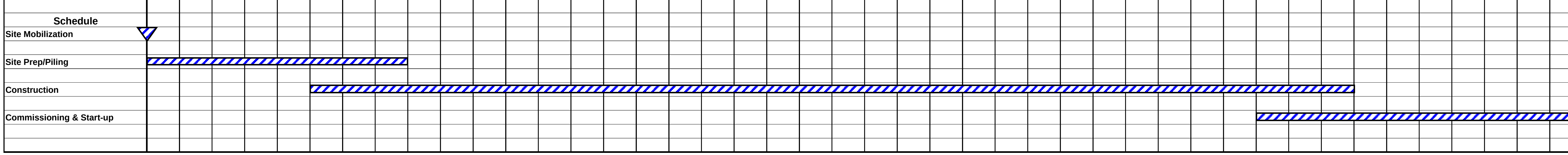
FLUOR®

Revision E, April 8, 2009

Months after Mobilization

Job Category	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22
CRAFT																						
Boilermakers	0	0	0	0	0	0	0	0	0	0	0	0	0	3	3	3	9	15	15	15	29	32
Carpenters	0	3	3	3	8	8	8	35	48	58	85	85	87	87	87	87	150	136	141	141	141	128
Cement Finishers	0	0	0	0	0	0	0	5	8	11	16	16	16	16	16	16	16	13	16	16	16	13
Electricians	0	5	5	5	16	16	16	16	16	7	7	7	12	13	13	13	15	16	16	16	74	76
Insulation Workers	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Iron Workers	0	1	1	1	4	4	4	13	17	19	28	28	29	51	62	84	87	84	90	102	119	150
Laborers	10	15	15	15	29	29	33	45	51	42	53	53	60	60	59	54	81	79	83	84	88	85
Millwrights	0	1	1	1	4	4	4	4	4	2	2	2	3	9	8	8	21	32	33	33	62	68
Operators	16	16	16	14	15	15	21	31	40	35	38	38	41	39	33	26	30	41	49	58	85	98
Painters	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pipefitters	0	1	1	1	4	4	4	67	131	129	129	129	130	83	19	19	53	85	150	213	422	502
Sheet Metal Workers	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2	2	3	3	3	3
Teamsters	0	2	2	2	5	5	6	6	6	4	4	4	5	5	5	3	4	6	6	6	6	6
Off plot Construction craft	6	6	6	6	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
Craft Subtotal	**32**	**51**	**51**	**49**	**98**	**98**	**109**	**236**	**335**	**323**	**377**	**377**	**397**	**380**	**320**	**327**	**483**	**523**	**616**	**702**	**1060**	**1176**
STAFF																						
Management	4	4	7	7	7	7	11	15	15	19	34	41	49	52	60	60	60	75	82	90	97	105
Engineering	2	2	2	2	2	4	4	6	10	10	10	10	10	12	14	15	15	15	15	15	15	15
Document Control	2	2	2	2	2	2	4	4	5	5	5	5	6	6	6	6	6	6	6	6	6	6
Subcontractors Staff	3	5	5	5	10	10	11	24	34	32	38	38	40	38	32	33	48	52	62	70	106	118
Off plot construction staff	1	1	1	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Commissioning																						
Admin / Operating Staff																						
Staff Subtotal	**12**	**13**	**17**	**17**	**23**	**25**	**32**	**50**	**65**	**67**	**88**	**95**	**106**	**110**	**113**	**115**	**130**	**149**	**166**	**182**	**226**	**245**
Project Total	**44**	**64**	**68**	**65**	**120**	**122**	**141**	**286**	**400**	**390**	**464**	**472**	**502**	**490**	**433**	**442**	**613**	**672**	**782**	**884**	**1286**	**1421**

Job Category	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44
CRAFT																						
Boilermakers	32	29	29	23	15	15	6	6	6	6	3	0	0	0	0	0	0	0	0	0	0	0
Carpenters	128	128	128	128	123	123	119	119	119	108	108	81	81	82	82	82	81	77	77	0	0	0
Cement Finishers	13	13	13	13	11	11	8	8	8	5	5	0	0	0	0	0	0	0	0	0	0	0
Electricians	76	154	157	157	156	184	185	214	242	249	276	275	224	176	138	110	52	37	37	0	0	0
Insulation Workers	0	0	0	2	3	5	8	10	12	13	16	16	16	18	16	15	8	5	5	0	0	0
Iron Workers	150	149	116	91	84	84	77	44	44	29	16	7	7	6	6	5	5	3	3	0	0	0
Laborers	85	84	86	85	77	78	79	78	79	81	81	69	67	68	67	65	61	47	47	0	0	0
Millwrights	68	62	62	50	32	32	14	14	14	15	10	4	4	4	4	4	4	2	2	0	0	0
Operators	98	94	96	89	80	82	79	75	76	76	67	56	53	37	35	26	22	17	17	0	0	0
Painters	0	0	0	0	0	7	9	10	12	14	15	15	17	19	19	17	10	7	7	0	0	0
Pipefitters	502	496	506	484	508	518	479	490	500	511	442	362	362	235	193	119	99	76	76	0	0	0
Sheet Metal Workers	3	3	3	3	2	2	0	0	1	1	1	1	1	1	1	1	0	0	0	0	0	0
Teamsters	6	5	6	6	4	4	5	5	5	6	6	6	6	6	6	6	6	4	4	0	0	0
Off plot Construction craft	15	15	15	15	21	21	21	21	21	21	21	21	21	21	21	21	11	11	11	11	11	11
Craft Subtotal	**1176**	**1232**	**1216**	**1147**	**1115**	**1166**	**1089**	**1094**	**1139**	**1136**	**1068**	**912**	**859**	**673**	**589**	**471**	**358**	**285**	**285**	**11**	**11**	**11**
STAFF																						
Management	105	105	106	106	106	106	106	106	106	105	105	105	97	97	75	25	22	15	15	8	0	0
Engineering	15	15	15	15	15	15	15	15	15	15	15	15	15	15	10	10	10	10	5	5	5	5
Document Control	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	5	5	5	5	4	3	2
Subcontractors Staff	118	123	122	115	112	117	109	109	114	114	107	91	86	67	59	47	36	29	29	1	1	1
Off plot construction staff	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1	1
Commissioning						10	10	10	20	30	30	30	30	30	30	30	30	30	30	20	20	20
Admin / Operating Staff							40	40	40	40	50	50	50	75	75	75	87	87	87	87	87	87
Staff Subtotal	**245**	**250**	**250**	**243**	**241**	**256**	**288**	**288**	**303**	**311**	**314**	**299**	**286**	**292**	**257**	**194**	**191**	**177**	**172**	**126**	**117**	**116**
Project Total	**1421**	**1482**	**1466**	**1390**	**1356**	**1422**	**1377**	**1382**	**1442**	**1447**	**1382**	**1211**	**1145**	**966**	**845**	**665**	**550**	**462**	**457**	**137**	**128**	**254**



Notes:

(1) These are approximate values

(2) Off plot include preliminary estimates for work performed outside of the plot (pipe and transmission lines)

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Table 2-26
Hydrogen Energy California, Kern County Power Project
Construction Equipment Estimate

FLUOR®

Revision E, April 8, 2009

Equipment	Number of Units	Months after Mobilization																																									
		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44
Truck Crane - Greater than 300 ton	38															1	1	1	1	1	2	2	2	3	3	3	3	3	3	3	2	2	1	1											
Truck Crane - Greater than 200 ton	72												1	1	1	1	1	2	2	3	3	4	4	4	4	4	4	4	4	4	4	4	3	3	2	2	2	1							
Crane - Mobile 65 ton	119													1	2	4	5	5	5	6	6	6	6	6	6	6	6	6	6	6	6	5	5	4	4	3	2	2							
Cranes - Mobile 45 ton	74											2	2	2	2	2	2	2	2	4	4	4	4	4	4	4	4	4	4	4	2	2	2	2	2	2	1	1							
Cranes - Mobile 35 ton	163							1	1	1	4	4	4	4	7	7	7	7	7	7	7	7	7	7	7	7	7	5	5	5	5	5	5	5	5	2	2	2	1	1	1	1	1	1	1
Bulldozer D10R	23	3	3	3	2	2	2	2	2	2	1	1																																	
Bulldozer D4C	26	3	3	3	3	2	2	2	2	2	2	1	1																																
Excavator - Trencher (CAT320)	0																																												
Excavator - Earth Scraper 637	22	5	5	5	5	2																																							
Excavator - Motor Grader (CAT140H)	16	3	3	2	2	2	2	2																																					
Excavator - Backhoe/loader	58	2	2	3	4	4	4	4	4	4	4	4	2	2	2	2	2	1	1	1	1	1	1	1	1	1																			
Excavator - loader	24	2	2	2	2	2	2	2	2	2	2	2	2																																
Vibratory Roller Ingersol-Rand 20 ton	40	5	5	5	5	2	2	2	2	2	2	2	2	2	2																														
Portable Compaction Roller	50			3	3	3	3	3	3				2	2	2	2	2	2	2	2	2	2								2	2	2	2	2	2										
Truck - Water	58	4	4	4	4	2	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1									
Forklift	76								1	1	1	2	2	2	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	2	2	2	2	1	1	1	1	1	1	1	1	1	1	1
Dump Truck	34	3	4	4	3	3	3	3	3	3	3	1	1																																
Service Truck - 1 ton	82	1	2	2	4	4	4	4	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1	1	1	1	1	1	1	1	1
Truck - Fuel/Lube	44	1	2	2	1	1	1	2	2	2	2	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1							
Concrete Pumper Truck	20									1	1	2	2	2	2	2	2	2	1	1	1	1																							
18 cy fill mat'l haul truck	280				20	20	20	20	20	20	20	20	20	20	15	15	10	10	10	10	5	5																							
Trucks - Pickup 3/4 ton	502	5	5	5	5	5	6	7	8	8	8	8	9	11	11	11	12	12	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	12	12	12	9	9	6	6
Trucks - 3 ton	159	1	1	1	1	1	1	1	1	2	2	2	2	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	4	3	1	1	1	1				
Diesel Powered Welder	101				1	1	1	1	1	1	1	1	1	1	1	1	2	2	2	2	2	2	3	3	4	5	5	5	5	5	5	5	5	5	4	4	4	2	2	1	1	1	1	1	1
Light Plants	215					2	2	2	2	2	2	2	2	6	6	6	6	6	6	6	6	6	6	8	8	8	8	8	8	8	8	8	8	8	8	8	8	4	4	4	3	3	3	3	3
Portable Compaction - Vibratory Plate	45								3	3	3	3	3	3	3	3	3	3	3	3	3	3	3																						
Portable Compaction - Vibratory Ram	0																																												
Articulating Boom Platform	0																																												
Pumps	89	3	3	3	3	3	3	3	3	3	3	3	2	2	2	2	2	1	1	1	1	2	2	2	2	2	2	2	2	2	2	2	2	3	3	3	3	1	1	1	1	1	1		
Air Compressor 185 CFM	0																																												
Air Compressor 750 CFM	97	1	1	1	1	1	1	1	1	2	2	2	2	2	2	2	4	4	4	4	4	4	4	4	4	4	4	4	4	4	2	2	2	2	1	1	1	1	1	1	1	1	1	1	1
Concrete Vibrators	38							1	2	3	3	3	3	3	3	3	3	3	2	2	1	1	1	1																					
Concrete Trowel Machine	26									2	2	2	2	2	2	2								2	2	2	2	2	2																
Fusion Welder	0																																												
Portable Power Generators	133	1	1	1	1	1	1	1	2	2	2	4	4	4	4	4	4	5	5	5	5	5	5	5	5	5	5	5	5	5	4	4	4	3	3	3	2	2	1	1	1	1	1	1	
Pile Driver Truck	15			1	3	3	3	3	2																																				
Fired Heaters	113					1	2	2	3	3	3	5	5	5	5	5	5	5	5	5	5	5	4	4	4	4	4	4	4	4	4	4	4												
Heavy Haul / Cranes	32																				4	4	4	4	4	4	4	4																	
Cranes 100 / 150 ton cap	79												2	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	2	2	2	2	2	1	1	1								
Misc equip for off plot construction (2)	364	6	6	6	6	12	12	12	12	12	12	12	12	12	12	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	6	6	6	6	6	6	6	6	6	6
Project Total	**3327**	**49**	**52**	**56**	**79**	**79**	**79**	**83**	**86**	**87**	**89**	**94**	**95**	**104**	**104**	**101**	**98**	**98**	**99**	**103**	**102**	**104**	**96**	**98**	**98**	**99**	**98**	**96**	**92**	**90**	**83**	**82**	**79**	**74**	**68**	**58**	**53**	**41**	**31**	**30**	**29**	**25**	**25**	**21**	**20**

Schedule

Site Mobilization

Site Prep/Piling

Construction

Commissioning & Start-up

Notes:

1 These are approximate values

2 Misc. equip for off plot include preliminary estimates for work performed outside of the plot (pipe and transmission lines)

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- Construction Worker Route 2 – locally sourced or temporary workers lodging in Metropolitan Bakersfield and nearby communities via Taft Highway (SR 119) to northbound Tupman Road, then turn left into the Project Site.

- Material Delivery and Construction Haul Route – westbound Stockdale Highway, turn left on southbound Dairy Road (local road), continuing across Adohr Road and then turn left into the Project Site.

Some of the heavy equipment is expected to be delivered via rail, however, due to its weight and size. Rail lines are located in Bakersfield and Buttonwillow near the Project Site where these heavy loads will be transferred to heavy duty trailers. These deliveries will comply with Caltrans regulations and weight restrictions for state highways.

Based on a peak month workforce requirement of 1,500 and an average vehicle occupancy rate of 1.3 people per vehicle, it is estimated that an average of about 2,300 total vehicle trips (1,150 round trips) per day will result from construction worker traffic. In addition to the workforce traffic, it is anticipated that an average of 100 total truck trips (50 truck round trips) per day will be required for construction equipment and material deliveries during the construction period, and an average of 320 total truck trips (160 truck round trips) per day will be required for import fill deliveries during the construction period.

Security measures will be incorporated at the access gates to control construction traffic.

Table 2-26, Construction Equipment Estimate, shows the type of construction equipment that will be used during construction of the Project, including commissioning and startup. It can be assumed that most of this equipment will also be used during the early construction phase of the on-site development. This equipment list includes trucks, cranes, bulldozers, excavators, rollers, forklifts, and pumpers.

Overall, traffic impacts associated with Project construction are not expected to be substantial.

2.6.4.1 Traffic Control Plan During Construction

An On-site Traffic Control Plan will be developed prior to construction. This plan will assist in the development of roads on site, parking areas, security issues, and site access. Additionally, the plan will be used to develop protocol for the movement of heavy-haul equipment on site. Additional features of the plan may include the following:

- Using proper signs and traffic control measures in accordance with Caltrans, particularly pertaining to nearby roads under their jurisdiction.
- Installing crossing structures if needed to avoid obstructing roads.
- Coordinating construction activities with the appropriate jurisdiction, such as the county, if closures of major roads are necessary during transmission line or pipeline construction.
- Scheduling of traffic lane or road closures during off-peak hours whenever possible.
- Limiting vehicle traffic to approved access roads, construction yards, and construction sites.
- Constructing off-site pipelines in accordance with applicable state and local encroachment permit requirements and covering trenches in roadways during non-work hours.

A detailed traffic control plan, pursuant to Caltrans and county requirements, will be developed and submitted at the request of the CEC. The Project will obtain the appropriate transportation-related permits prior to construction.

2.7 FACILITY SAFETY DESIGN

Inherently Safer Design Philosophy

The "Inherently Safer Design Process" will be implemented to deliver a safer design for the Project. The Inherently Safer Design Process is focused on the following:

- Mitigate risks associated with inherent hazards
  - Throughout the work process: inherent hazards are identified, assessed, understood, documented, and mitigated.

- Minimize potential causes and reduce severity
  - Opportunities to minimize risks at the source will be evaluated. This process includes identifying the actual risks and considering what is to be done to mitigate them. At the conclusion of this activity, a decision is made to implement those measures that are feasible and practicable and that are likely to reduce the potential severity of identified potential risks. This includes reducing on-site inventory of hazardous materials to the amount necessary to support operations.

- Manage the Process to:
  - Increase equipment integrity, equipment reliability, and longevity to minimize the probability of an unwanted event occurring.
  - Minimize potential risks throughout the design life of the Project.
  - Make certain that the risk management strategy has been accepted by those who will implement the strategy.
  - Ensure timely implementation of effective and reliable combinations of the identified mitigation measures to achieve desired goals.

Health, Safety, Security, and Environmental Design Focus Areas

The overall goal of "Health, Security, Safety, and Environmental (HSSE) in Design" is to protect human health (employees, contractors, and the general public), the environment, and property against possible accidents (fires, explosions, liquid spills to ground or to water, or unpermitted emissions to the air) resulting from the failures of facilities or components on the site.

The main focus of HSSE in Design is to ensure that adequate measures are used to minimize the risks and to mitigate the consequences of accidental hazardous material releases, fires, or explosions. While the probability of these incidents occurring may be low, each potential risk will be addressed, and methods identified to reduce them will be established.

During the course of operations the following focus areas (at a minimum) will be addressed:

- Review of unit and component location, access, and spacing for O&M
- Internal Project road layout and operating unit setbacks
- Fire water storage and distribution system
- Deluge system(s)
- Detect area/unit fire and gas
- Identification of all materials requiring MSDS documents

Health, Safety, Security, and Environmental Goals

The Project's objective is to achieve exemplary HSSE performance within all of its business activities. This is summarized in the Project's HSSE goals:

- People will be motivated and empowered to work safely and protect their long-term health.
- Processes will be provided to identify hazards and manage risks.
- Project will meet or exceed regulatory compliance requirements.
- Performance will be measured at all levels to ensure continuous improvement.

2.7.1 Natural Hazards

The Project will be planned, engineered, designed, constructed, and operated to meet the requirements of all applicable LORS as described in detail in Appendix B, Design Criteria. An overview of hazards that will be addressed in the Project is provided below.

Earthquake

The Project Site, like most of California, is within a seismically active region. A review of geologic literature did not identify the presence of any known active or potentially active faults at the Project Site or crossing the Project linears. Section 5.15, Geological Hazards and Resources, of this Revised AFC provides details on the potential geological hazards associated with the Project. Figure 5.15-1, Regional Geologic Map, does not show any faults mapped within the Project.

The closest known faults classified as active by the State of California Geologic Survey (CGS) are the San Andreas Fault, which is, according to Blake (2000), approximately 21 miles to the west of the Project Site the White Wolf fault located approximately 23 miles to the southeast, and the Pleito Thrust located approximately 27 miles south. These faults are shown on Figure 5.15-2, Regional Fault Map.

The following is a brief summary of the local earthquake hazards:

- The Project Site is located within a seismically active region.
- The San Andreas Fault is located approximately 21 miles to the west.
- The Project Site is susceptible to strong ground shaking during earthquakes on nearby faults.

- Based upon findings of the Geotechnical Investigation (Appendix P of this Revised AFC), the potential for liquefaction is low to nil and seismic-induced dry sand settlement is on the order of ¼ inch, which is low.

The Project Site is located in high earthquake zone and the mapped maximum credible accelerations and design response spectrum shall be determined from Section 1613A, California Building Code (CBC 2007).

The Project Site is located in Seismic Risk Zone 4. Structures, their foundations, and equipment anchors will be designed in accordance with the CBC 2007 and ASCE 7-05.

When there is conflict in code requirements, the most conservative requirements will govern. Also, the substation equipment will meet requirements of IEEE 693-1997 Recommended Practice for Seismic Design of Substations.

Floods

As discussed more fully in Section 5.15, Geological Hazards and Resources, of this Revised AFC, the Project Site is not located within an area identified as having flood hazards or shallow groundwater. The Project linears extending to the west and south of the Project Site will cross a flood hazard zone on the northeastern side of the California State Water Project.

Based on the Federal Emergency Management Agency Flood Insurance Rate Map "Kern County, California, and Incorporated Areas" (Map 06029C2225E), dated 2008, the Project Site is not in the 100-year flood zone.

Provided proper drainage design, the Project Site is not likely to experience flooding. As a result, impacts will be less than significant.

Wind Loads

The basic design wind speed (3-second gust) is 85 miles per hour as per CBC 2007. Wind loads on structures, systems, and components will be determined from ASCE 7-05 and CBC 2007.

2.7.2 Emergency Systems and Safety Precautions

2.7.2.1 Community and Stakeholder Awareness

The Project values the importance of community awareness in the Kern County area and will actively engage in dialogue with the community and various stakeholders to maintain public confidence in the integrity of Project's operations and products and the commitment to HSSE performance.

HSSE issues will be identified by listening and consulting with concerned employees, contractors, regulatory agencies, public organizations, and communities. All communications will be responded to in a timely manner.

The Project will establish and maintain open and proactive communications with employees, contractors, regulatory agencies, public organizations, and communities regarding the HSSE aspects of the Project.

2.7.2.2 Emergency Preparedness

The Project will develop and use communications and response plans for emergency situations in accordance with applicable LORS. Prior to any activity the response plan will be reviewed by the appropriate manager who will take necessary actions to prepare to respond to an emergency event. All plans will be coordinated with the local emergency response organizations within Kern County, and the Bakersfield area in particular. Area hospitals and clinical medical services have been identified along with fire protection.

2.7.2.3 Specific Project Emergency Systems

The Project's auxiliary systems described below support, protect, and control the Project.

Fire Protection

See Section 2.4.11, Fire Protection, for details on the fire protection system for the Project.

Lighting System

The lighting system provides plant personnel with illumination in both normal and emergency conditions. The system consists primarily of alternating current (AC) lighting, and includes direct current (DC) lighting for activities or emergency egress required during an outage of the Project's AC electrical system. Lighting fixtures will be directionally oriented, shielded, and hooded to minimize off-site migration of light. The electrical distribution system also provides AC convenience outlets for portable lamps and tools.

Grounding System

The Project's electrical systems and equipment are susceptible to ground faults, switching surges, and lightning, which can impose hazardous voltage and current on Project equipment and structures. To protect against personnel injury and equipment damage, the grounding system provides an adequate path to dissipate hazardous voltage and current under the most severe conditions. Bare conductor is installed below grade in a grid pattern, and each junction of the grid is bonded together by welding or mechanical clamps. The grid spacing is designed to maintain safe voltage gradients. Ground resistivity readings are used to determine the necessary grid spacing and numbers of ground rods. Steel structures and non-energized parts of Project electrical equipment are connected to the grounding grid.

Distributed Control System

The DCS provides control, monitoring, alarm, and data storage functions for Project systems.

The following functions will be provided:

- Control of the CTGs, STG, HRSGs, gasification and other process units, and balance-of-plant systems in a coordinated manner.
- Monitoring of operating parameters from Project systems and equipment, and visual display of the associated operating data to control operators and technicians.
- Detection of abnormal operating parameters and parameter trends, and provision of visual and audible alarms to apprise control operators of such conditions.
- Storage and retrieval of historical operating data.

The DCS is a microprocessor-based system. Redundant capability is provided for critical DCS components such that no single component failure will cause an outage. The DCS consists of the following major components:

- Visual display-based control operator interface (redundant)
- Visual display-based control technician workstation
- Multi-function processors (redundant)
- Input/output processors (redundant for critical control parameters)
- Field sensors and distributed processors (redundant for critical control parameters)
- Historical data archive
- Printers, data highways, data links, control cabling, and cable trays

The DCS is linked to any local control systems furnished by packaged equipment vendors.

Emergency Relief System

The Project is furnished with relief devices and three flares to protect equipment from overpressure. Any excess gas or liquid accumulated in equipment will be routed to the flares in the event of an emergency or upset condition.

Cathodic and Lightning Protection System

Cathodic protection may be provided using an impressed current or buried anode system to prevent corrosion of buried carbon steel piping and structures. Protective coatings are applied as primary protection and to minimize cathodic protection current requirements. The requirement for a cathodic protection system will be determined during detailed design. Lightning protection will be furnished for buildings and structures. Lightning protection for the switchyard will be installed in accordance with industry practice.

Personnel Protection Insulation

Though not required for process consideration, insulation will be provided on equipment and piping that operate above 140°F to avoid burn injuries.

Instrument Air System

The instrument air system provides dry, filtered air to pneumatic operators and devices throughout the Project. Air from the service air system is dried, filtered, and pressure-regulated prior to delivery to the instrument air piping network. This supports continual safe operation of the instruments controlling Project operation.

Emergency Facilities

Emergency services will be coordinated with the local fire department and hospital. An urgent care facility will be contracted to set up non-emergency physician referrals. First-aid kits will be provided around the Project Site and regularly maintained. One nurse and at least one person trained in first aid will be part of the construction staff. In addition, all foremen and supervisors will be required to have first-aid training. Fire extinguishers will be located throughout the Project Site at strategic locations at all times during construction.

Fire Safety Program

Prior to the beginning of construction, the contractor, the owner, Project management, and the assigned operations and management staff will meet and develop a site-specific fire safety program that coordinates construction activities with the owner's existing procedures. The developed programs will be reviewed with local government emergency response organizations to ensure completeness and proper coordination.

Additional requirements that are unique to construction will necessitate the development of construction-specific programs. The construction contractor's safety program will include safety procedures that address welding, thermal cutting, and gas cylinders; fire protection; and emergency response.

Emergency Response Procedures

Prior to commencement of construction activities, the contractor, the owner, Project management, and the assigned operations and management staff will meet and develop a site-specific construction emergency response program. A review of the developed programs with local government emergency response organizations will ensure completeness and proper coordination.

2.8 TECHNOLOGY SELECTION AND FACILITY RELIABILITY

2.8.1 Technology Selection

This section explains how the technology being used within the Project is demonstrated within other industrial commercial scale applications, and how this relates to the actions taken to maximize the reliability of the Project.

It is now widely recognized that carbon capture and sequestration has a central role to play in emissions reduction because it can help reconcile the continued use of fossil fuels with the need to reduce emissions. Numerous studies, including by the Electric Power Research Institute, (EPRI 2007) Massachusetts Institute of Technology, Princeton (Pacala and Socolow 2004) and others have stressed the major role carbon capture and sequestration must play in meeting targets for GHG emissions reduction in California, the United States as a whole, and the world.

The Project team studied the technological, commercial, permitting and all other aspects of feasibility to potentially build and operate an IGCC power generation facility capable of creating approximately 250 MW low-carbon power from solid fuel in Kern County, California.

HEI was formed to potentially develop a material business consisting of the production of hydrogen fuel for the generation of low-carbon power. Accordingly, the Project is intended to generate baseload low-carbon power using hydrogen-rich fuel produced from petcoke or a coal/coke blend. The feasibility review for the technology selection has two key objectives:

- Proving commercial scale IGCC with carbon capture operability at high capture rates and low emissions; and
- Proving associated economic viability. A key aspect is delivering a highly reliable operating plant within a minimum period after initial startup.

To deliver these objectives, the Project has a preference to select, where available, standard and proven technology and equipment that is operating within the industry at equivalent capacities and design criteria, to reduce the overall risk on the Project associated with the fact that the IGCC system with carbon capture and storage has not been demonstrated.

Both petcoke gasification and gas purification with carbon capture are proven technologies, operating at commercial scale within the United States and around the world. The integration of these technologies with sequestration has not yet been performed on a commercial scale. Three IGCC plants are operating in the United States with 100 percent petcoke or petcoke/coal blends feedstocks (TECO/Tampa, SG-Solutions/Wabash, Valero/Delaware), with an additional 12 operating worldwide. All operate without carbon capture and sequestration. A substitute natural gas (SNG) plant operates in North Dakota that includes gasification, gas purification and carbon capture and sequestration, but it does not generate electricity. Coffeyville Industries in Kansas operates a chemical plant which uses a similar front-end arrangement to the Project: petcoke gasification in a GE quench gasifier, sour shift, low temperature gas cooling, AGR to produce carbon dioxide and hydrogen, and an SRU to remove sulfur. The carbon dioxide and hydrogen in the Coffeyville are then directed to urea production, as opposed to EOR/sequestration and low-carbon power generation on the Project.

The following sections of this Revised AFC contain information regarding the demonstrated feasibility of the technologies to be used in the Project:

- Section 6.4.1, General Electric Gasification Technology, “GE has the greatest experience of designing solid fuel gasifiers. GE had more than 10 operating facilities at the time of selection”;

- Section 6.4.2, Acid Gas Removal System, “there are over 50 Rectisol plants in operation”;

- Section 6.4.3, General Electric 7FB Combustion Turbine, "GE has demonstrated more than 100,000 hours on F class turbines in syngas service at the SG-Solutions Wabash IGCC and the TECO Polk IGCC power plants. GE originally developed the 7FB combustion turbine for natural gas-fired combined cycle applications. The first commercial unit started operating in 2002, and there are now ten operating 7FB (60 Hz) units in the U.S. with a total of greater than 35,000 hours of operation, and thirteen operating comparable 9FB (50 Hz) units in Europe with a total of greater than 74,000 hours of operation."

Regarding the other units within the Project, General Electric LMS100 auxiliary turbine is a proven technology with 2,000 fired hours at the Basin Electric plant in Groton, North Dakota. HRSG and emission control facilities operate on many natural gas turbines in California and around the world. Carbon dioxide compression is practiced at the North Dakota SNG plant at similar production pressures and rates for pipeline transportation to EOR facilities, and is also practiced at slightly different flowrates/pressures in the Four Corners area of the United States where naturally occurring carbon dioxide is compressed for pipeline transportation, as well as other carbon dioxide compression facilities around the world. The Process Wastewater ZLD system takes process wastewater and treats it using industry standard technology to produce a purified water stream that is recycled for reuse within the Project and a solid waste for off-site disposal in accordance with applicable LORS. The Tampa Electric IGCC plant in Polk County, Florida treats process water in a similar ZLD system to produce a recycled water stream and a solid waste for off-site disposal. The remaining systems within the Project are commercially proven technologies operating at facilities in the United States and around the world: water treatment plant, plant wastewater ZLD system, heat rejection cooling system, solids handling system with particulate abatement systems, sour shift, low temperature gas cooling, mercury removal, flares, ASU, SRU, auxiliary boiler, and resource linear pipelines.

2.8.2 Facility Reliability

In addition to the above approach of selecting proven technologies where available, the Project critically analyzed each unit within the Project to determine its reliability and impact on the reliability of the whole Project based on historic reliability data from actual operating plant. This enabled decisions such as whether to select an installed pump, or adopt enhanced preventative maintenance procedures.

The Project is designed for an operating life of a minimum of 20 years. O&M procedures will be consistent with industry standard practices to maintain the useful life status of Project components. The hydrogen-rich fuel availability for mature operation is estimated to be greater than 80 percent. The power availability for mature operation is estimated to be greater than 90 percent. The primary fuel to the gas turbine is hydrogen-rich fuel, with natural gas as a backup fuel when hydrogen-rich fuel is not available, due to, for example, maintenance of the Gasifier unit. The commissioning and startup period of the Project is expected to be completed within approximately 1 year from mechanical completion. Commercial operation will start when the commissioning and startup activities are completed and the licensor/contractor guarantees and milestones have been achieved.

In addition to the IGCC operation, a simple cycle gas turbine using GE LMS100 technology is used as a peaker and backup power supply for the IGCC. The design life is expected to be at least 20 years, and reliability is estimated to be 98 percent.

GE gasification technology for solid fuels has been demonstrated in many commercial applications worldwide. The GE gasification technology for 100 percent petcoke feed is currently used in the Valero Refinery in Delaware and the Coffeyville Resources Ammonia Plant in Kansas. The GE gasification technology for mixed petcoke and coal operation has been demonstrated at Tampa Electric IGCC in Florida and in different chemical plants in China.

The downstream unit technologies (including carbon monoxide sour gas shift reactors, AGR technology, and Claus sulfur removal technology) have been demonstrated in commercial applications in the United States (including Eastman Chemical Plant in Tennessee) and many chemical plants in China (mostly ammonia and methanol plants).

The gas turbine technology employed in this project is the GE Frame 7FB. Both Tampa Electric and Duke Wabash IGCC facilities in Indiana have been operating the 7FA gas turbine, which is substantially similar to the 7FB, on syngas over the last 15 years. The remaining components of the power block (HRSG, steam turbine, and generator) will employ conventional proven technology.

To incorporate the lessons learned from the existing IGCC in the United States and worldwide, the following design features are included.

A constant supply of oxygen is important to reliable operation of the Project. This constant supply is achieved by installing LOX storage in the event of a short outage of the ASU.

Most existing solid feedstock IGCCs do not have spare gasifiers, and consequently their availability is typically at or below 80 percent. Chemical plant gasification units ordinarily have a spare gasifier or a spare gasification train, which results in high reliability (95 to 99 percent), as reported in the literature (Eastman Chemical Plant in Tennessee, Coffeyville Ammonia Plant, and many Chinese gasification units). The Project incorporates one complete spare gasification train. Each gasification train will be shut down on a planned basis to perform the required maintenance. Because of the proactive scheduled maintenance, it is expected that unplanned outage of the gasification train can be minimized.

The Project includes two SRUs. In the event of the outage of one SRU, the other SRU can be ramped up to partially take up the duty. In the meantime, the feedstock can be adjusted to a lower sulfur blend so that the total throughput (in terms of power production) will not be compromised significantly by the outage of one of the two SRUs.

Because of the scheduled maintenance of the GE 7FB gas turbine, the entire IGCC complex will be shut down when the power block is out of service. The remaining process block (AGR, Shift reactors, low temperature cooling section) has demonstrated high reliability in historical industry practice. However, in order to match the gas turbine outage schedule, the process block will also be shut down during the gas turbine scheduled maintenance period. This offers an opportunity to perform much of the maintenance for the AGR and Shift systems in a manner that can further enhance the reliability of the Project.

Table 2-27, Operational Modes, presents the operational parameters and outputs associated with the various operational modes.

Table 2-27
Operational Modes

Year	Estimated Hydrogen (H^2)-Rich Gas Availability	Estimated Power Availability	H^{2-}Rich Gas Hours	Natural Gas Hours	H^{2-}Rich Gas Gross MWh	Natural Gas Gross MWh
1	**65.0%**	**91.2%**	5,690	2,302	2,218,961	764,382
2	**74.4%**	**92.6%**	6,520	1,592	2,542,663	528,660
3	**83.5%**	**91.5%**	7,319	697	2,854,238	231,551
4	**89.0%**	**93.7%**	7,800	408	3,042,182	135,301
5	**89.0%**	**93.7%**	7,800	408	3,042,182	135,301
6	**80.4%**	**86.8%**	7,043	565	2,746,842	187,519
7	**89.0%**	**93.7%**	7,800	408	3,042,182	135,301
8	**89.0%**	**93.7%**	7,800	408	3,042,182	135,301
9	**83.5%**	**91.5%**	7,319	697	2,854,238	231,551
10	**89.0%**	**93.7%**	7,800	408	3,042,182	135,301
11	**89.0%**	**93.7%**	7,800	408	3,042,182	135,301
12	**80.4%**	**86.8%**	7,043	565	2,746,842	187,519
13	**89.0%**	**93.7%**	7,800	408	3,042,182	135,301
14	**89.0%**	**93.7%**	7,800	408	3,042,182	135,301
15	**83.5%**	**91.5%**	7,319	697	2,854,238	231,551
16	**89.0%**	**93.7%**	7,800	408	3,042,182	135,301
17	**89.0%**	**93.7%**	7,800	408	3,042,182	135,301
18	**80.4%**	**86.8%**	7,043	565	2,746,842	187,519
19	**89.0%**	**93.7%**	7,800	408	3,042,182	135,301
20	**89.0%**	**93.7%**	7,800	408	3,042,182	135,301

Note
1 The gross MW is estimated to be about 390 MW for H2-rich gas operation mode, and about 330 MW for natural gas operation mode at average ambient conditions.

The simple cycle LMS100® gas turbine will enable peaking power supply during the times of high demand, as well as providing backup power supply for the gasification process block when the 7FB power block is not available, enabling the Project to return to normal production status within a minimum period of time.

BP and Rio Tinto both have a long history of project execution and operating experience, as well as high standards of engineering and safety design criteria. The EPC contractor will be a reputable company, with experience in handling large capital projects. Comprehensive training and simulation programs will be established to ensure the integrity of the design and safety awareness of all O&M personnel. The incorporation of applicable in house engineering and safety design criteria and the use of experienced and trained contractors, operators and personnel will also bolster the Project's reliability.

Going forward, Quality Management activities for critical items will be identified to ensure requisite reliability and maintainability, such as specifying design requirements, identifying condition monitoring and preventative maintenance requirements, holding Design Reviews with appropriate subject matter experts, operations and maintenance personnel. The use of appropriate engineering practices provides a set of design inputs into the Plant design which capture operating knowledge or practice that is not normally available from industry standards alone, practices which have shown to yield measurable benefits in reducing plant and facility down time and maintenance costs. Other sources of information will be used to maximize the reliability of the Project, such as the Tampa Electric Polk Power Station Technical Report (2002) for the DOE that discusses plant reliability problems and outages in great detail. Given this plant was a GE gasification project, it contains many lessons learned for the Project. A link to the document is: http://www.netl.doe.gov/technologies/coalpower/cctc/cctdp/bibliography/demonstration/pdfs/tampa/TampaFinal.pdf.

2.9 REFERENCES

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PROJECT VICINITY

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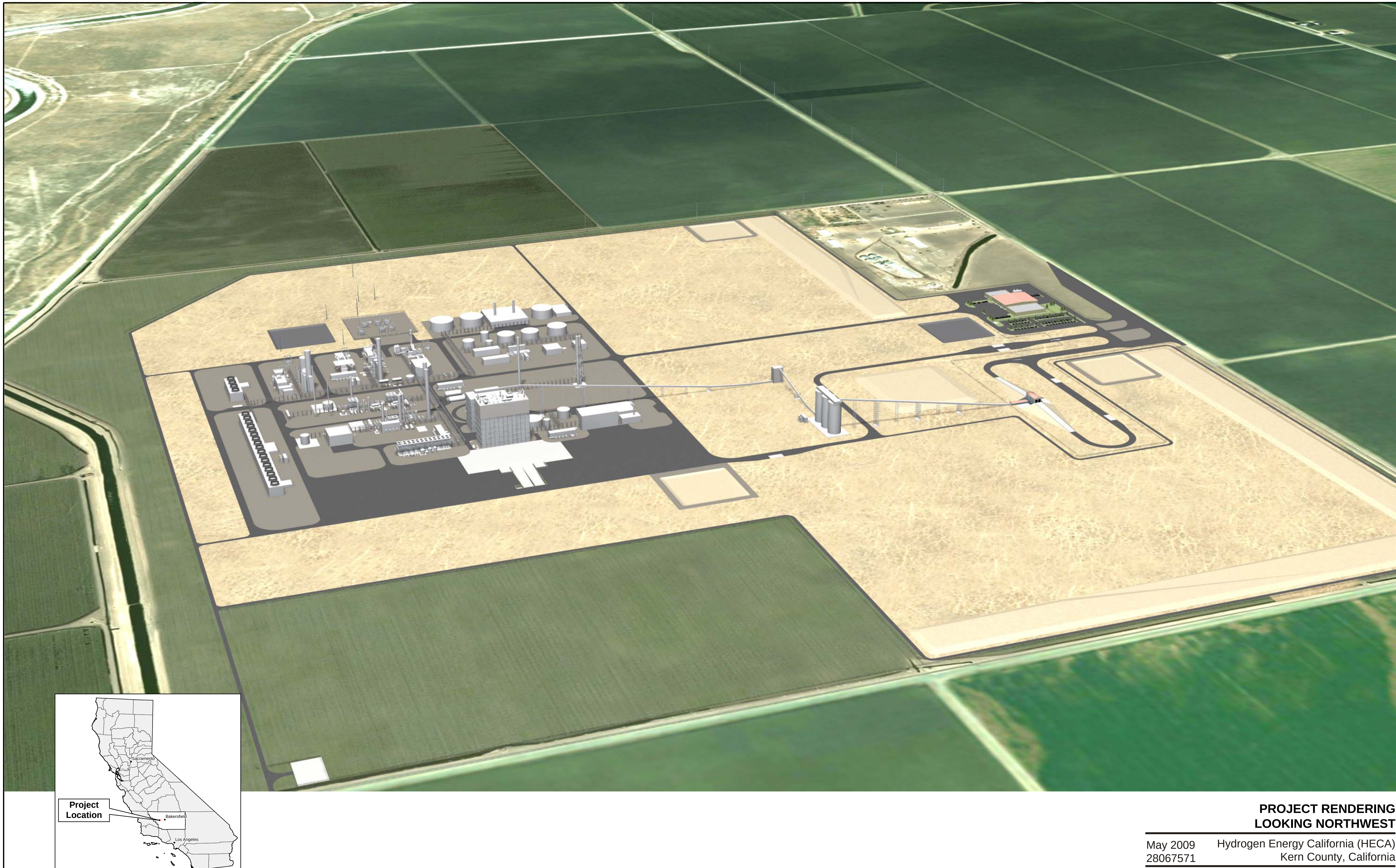
FIGURE 2-1

5/20/09 vsa..T:\HECA\GRAPHICS\2.0 Project Description\2-1_proj vicinity_8.5x11.ai



PROJECT RENDERING
LOOKING NORTHWEST

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Kern County, California

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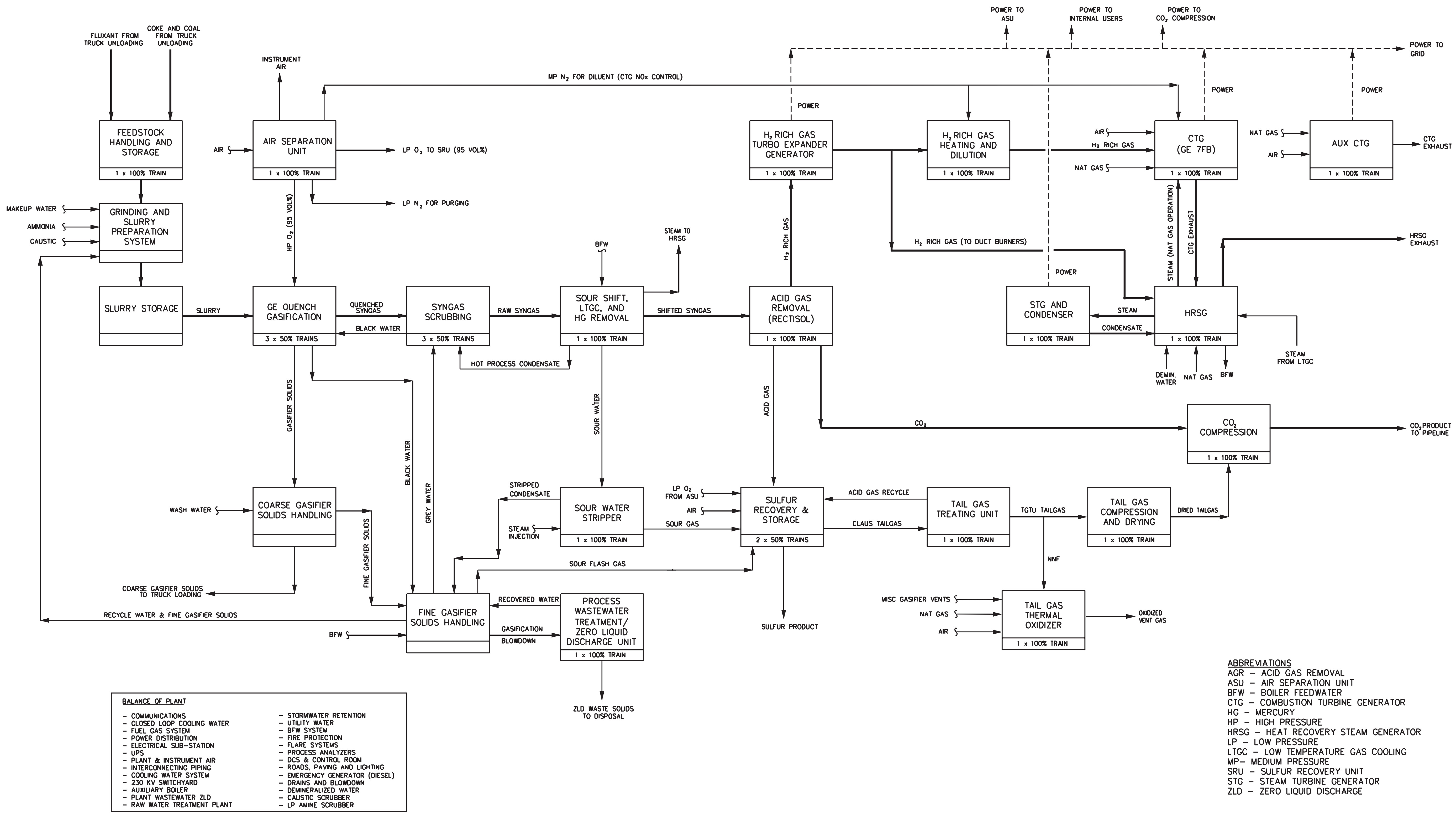
FIGURE 2-2



Source:
Fluor; Hydrogen Energy California, Kern County Power Project;
Block Flow Diagram; Drawing No: A3RW-BFD-25-001, Rev. 4 (04/13/09)

OVERALL BLOCK FLOW DIAGRAM

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Kern County, California

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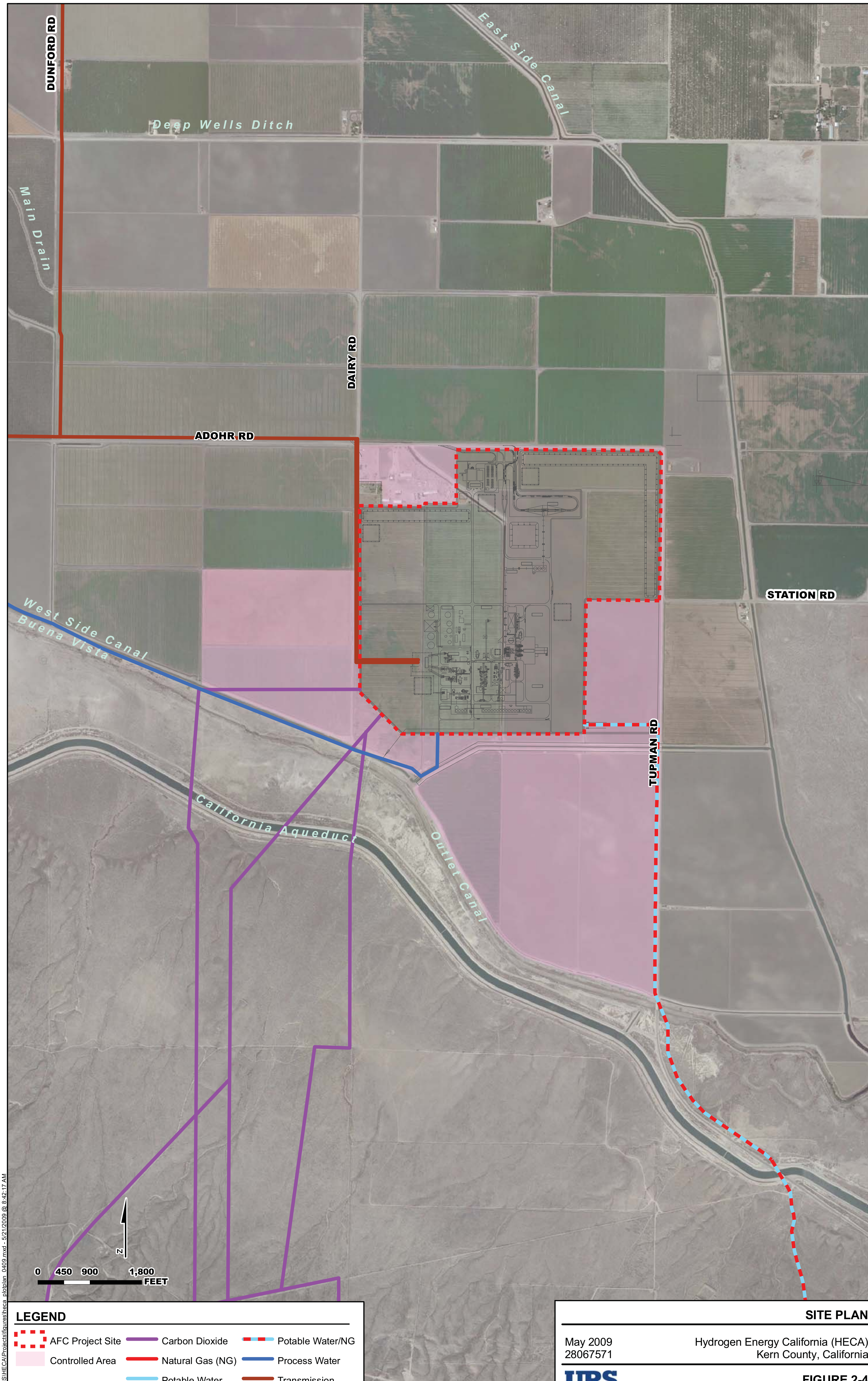
FIGURE 2-3



LEGEND

AFC Project Site
Controlled Area
Carbon Dioxide
Natural Gas (NG)
Potable Water
Potable Water/NG
Process Water
Transmission

SITE PLAN

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Hydrogen Energy California (HECA)
Kern County, California

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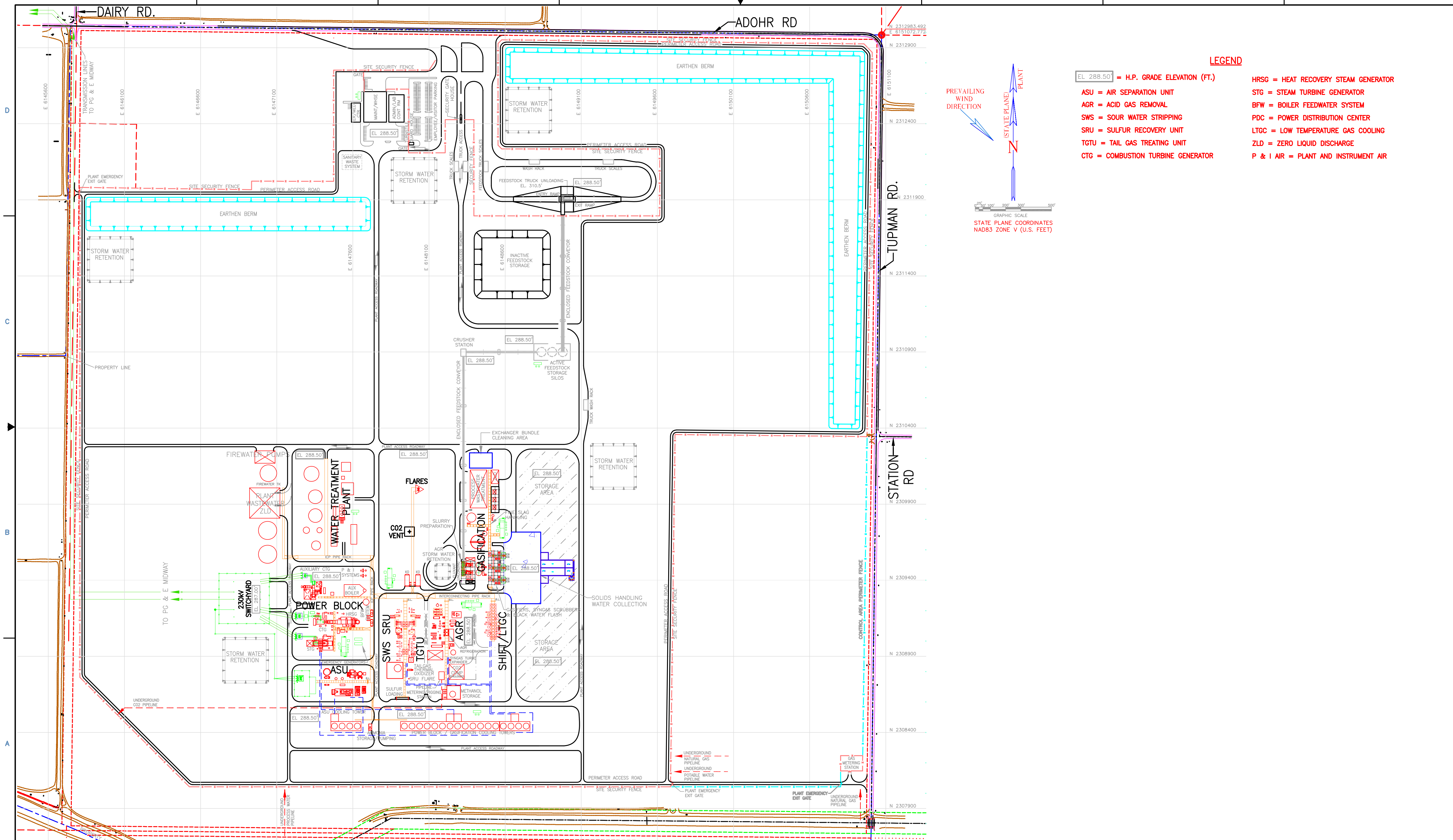
FIGURE 2-4

Aerial Photo, Digital Globe, June 1, 2008.



Source:
Fluor; Hydrogen Energy California, Kern County Power Project;
Preliminary Plot Plan; Drawing No: SK-250-1001, Rev. 0, 05/12/09

PRELIMINARY PLOT PLAN

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Kern County, California

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FIGURE 2-5

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LEGEND

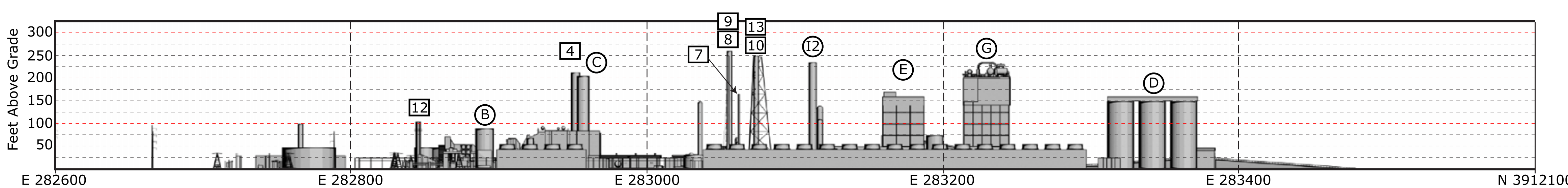
ASU = AIR SEPARATION UNIT
AGR = ACID GAS REMOVAL
SWS = SOUR WATER STRIPPING
SRU = SULFUR RECOVERY UNIT
TGTU = TAIL GAS TREATING UNIT
CTG = COMBUSTION TURBINE GENERATOR
HRSG = HEAT RECOVERY STEAM GENERATOR
STG = STEAM TURBINE GENERATOR
BFW = BOILER FEEDWATER SYSTEM
PDC = POWER DISTRIBUTION CENTER
LTGC = LOW TEMPERATURE GAS COOLING
ZLD = ZERO LIQUID DISCHARGE
P & I AIR = PLANT AND INSTRUMENT AIR

Notes:
1) Identifiers are same as shown in Figure 2-38, Preliminary Emissions Sources Plot Plan

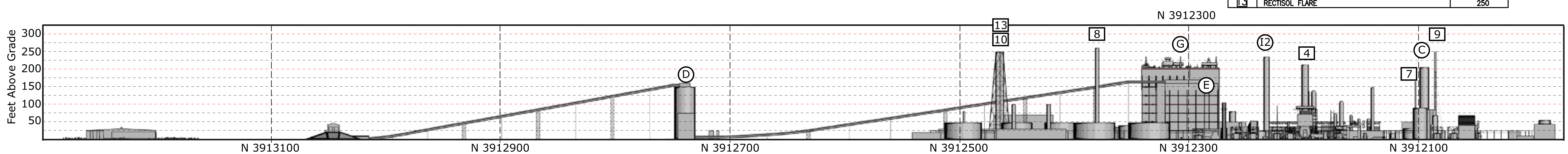
ELEVATIONS OF SIGNIFICANT STRUCTURES (See Note 1)

ID	DESCRIPTION	APPX. ELEVATIONS FROM GRADE (FT.)
A	ASU MAIN AIR COMPRESSOR ENCLOSURE	40
B	LIQUID OXYGEN STORAGE (LOX) TANK	90
C	AIR SEPARATION COLUMN CAN	205
D	FEEDSTOCK STORAGE SILOS	150
E	SLURRY PREPARATION BUILDING	165
F	SLURRY RUN TANKS (QTY 2)	75
G	GASIFICATION STRUCTURE	200
H	FINE SLAG HANDLING ENCLOSURE	70
I1	AGR REFRIGERATION COMPRESSOR ENCLOSURE	40
I2	AGR METHANOL WASH COLUMN	235
J	CO2 COMPRESSOR ENCLOSURE	50
K	STEAM TURBINE GENERATOR STRUCTURE	50
L	COMBUSTION TURBINE GENERATOR STRUCTURE	50
M1	HEAT RECOVERY STEAM GENERATOR STRUCTURE	90
M2	AUXILIARY CTG STRUCTURE	45
M3	AUXILIARY BOILER STRUCTURE	50
N	FLARE K.O. DRUMS (QTY 2)	35
O	POWER DISTRIBUTION CENTERS	25
Q	GREY WATER TANK	30'DIA X 40'H
R	SETTLER	85'DIA X 35'H
S	METHANOL STORAGE TANK	40'DIA X 40'H
T	SOUR WATER STRIPPER FEED TANK	48'DIA X 32'H
U	PROCESS WASTEWATER TREATMENT FEED TANK	60'DIA X 40'H
V	CONDENSATE STORAGE TANK	34'DIA X 24'H
W1	RAW WATER TANK	100'DIA X 48'H
W2	TREATED WATER TANK	90'DIA X 40'H
W3	PURIFIED WATER TANK	90'DIA X 48'H
W4	BACKWASH TANK	42.5'DIA X 48'H
W5	UTILITY WATER TANK	35'DIA X 32'H
W6	DEMINERALIZED WATER STORAGE TANK	60'DIA X 40'H
X	FIREWATER STORAGE TANK	110'DIA X 48'H
Y1	PLANT WASTEWATER ZLD FEED TANK-A	120'DIA X 48'H
Y2	PLANT WASTEWATER ZLD FEED TANK-B	120'DIA X 48'H
1	ASU COOLING TOWER	55
2	POWERBLOCK & GASIFICATION COOLING TOWERS	55
3	EMERGENCY GENERATORS	20
4	HRSG STACK	213
5	FIRE WATER PUMP DIESEL ENGINE	20
6	AUXILIARY BOILER	80
7	TAIL GAS THERMAL OXIDIZER	165
8	CO2 VENT	260
9	SRU FLARE	250
10	GASIFICATION FLARE	250
11a	GASIFIER WARMING VENT	210
11b	GASIFIER WARMING VENT	210
11c	GASIFIER WARMING VENT	210
12	AUXILIARY CTG STACK	110
13	RECTISOL FLARE	250

TANKS SET AT GRADE ELEVATION



VIEWING NORTH



VIEWING EAST
UTM Zone V, NAD83 (METERS)

PROJECT ELEVATIONS

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Kern County, California

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FIGURE 2-6

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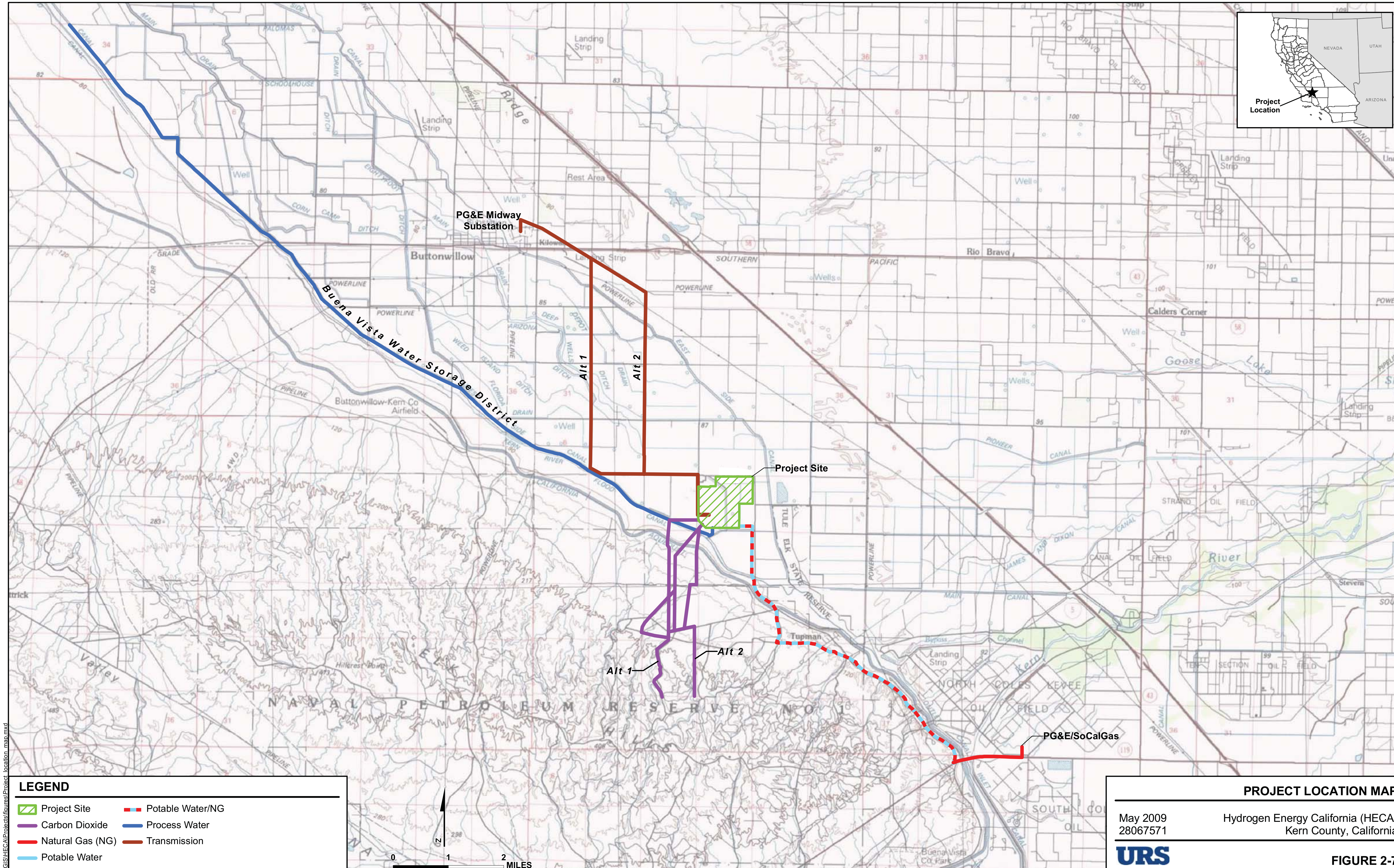
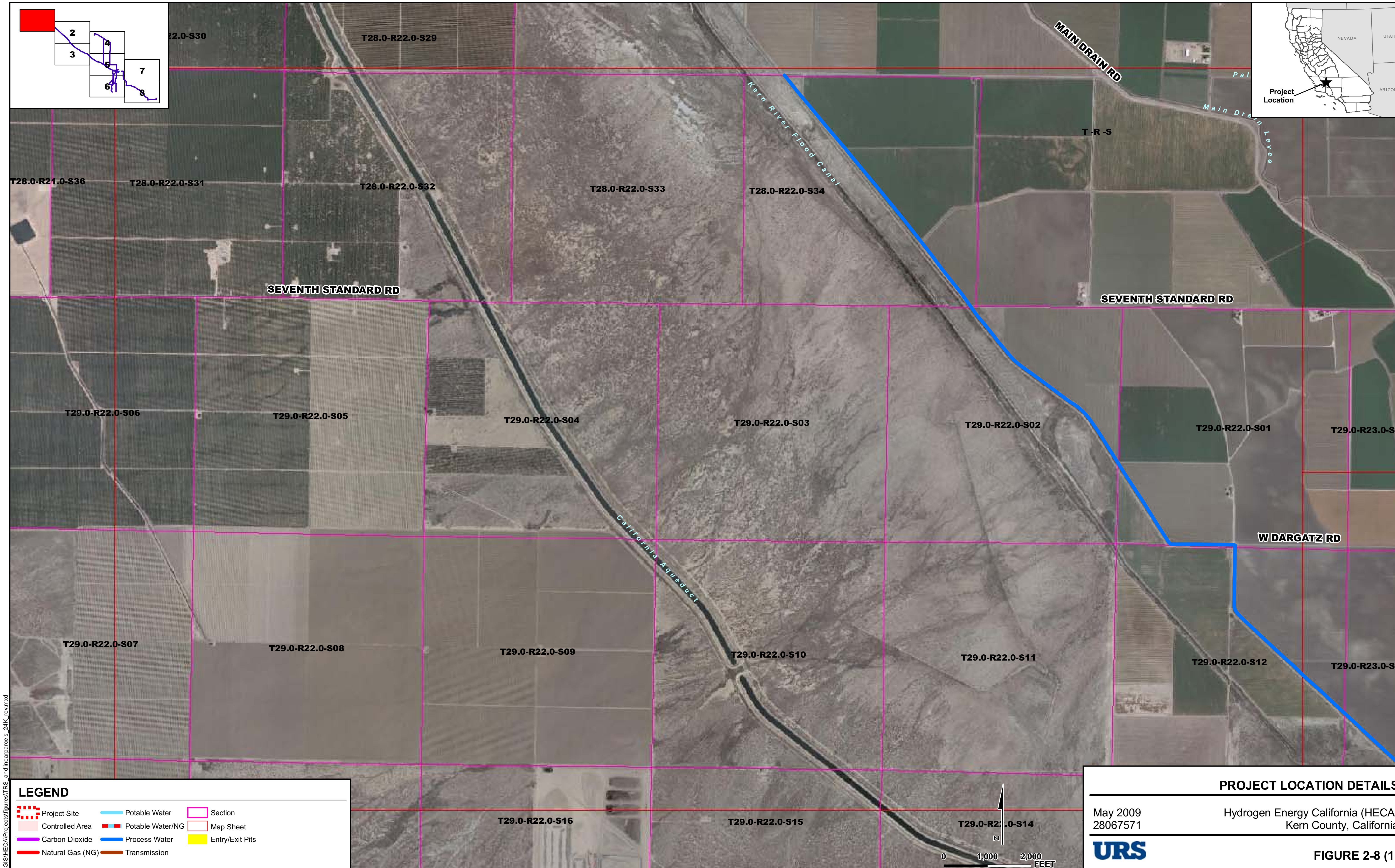
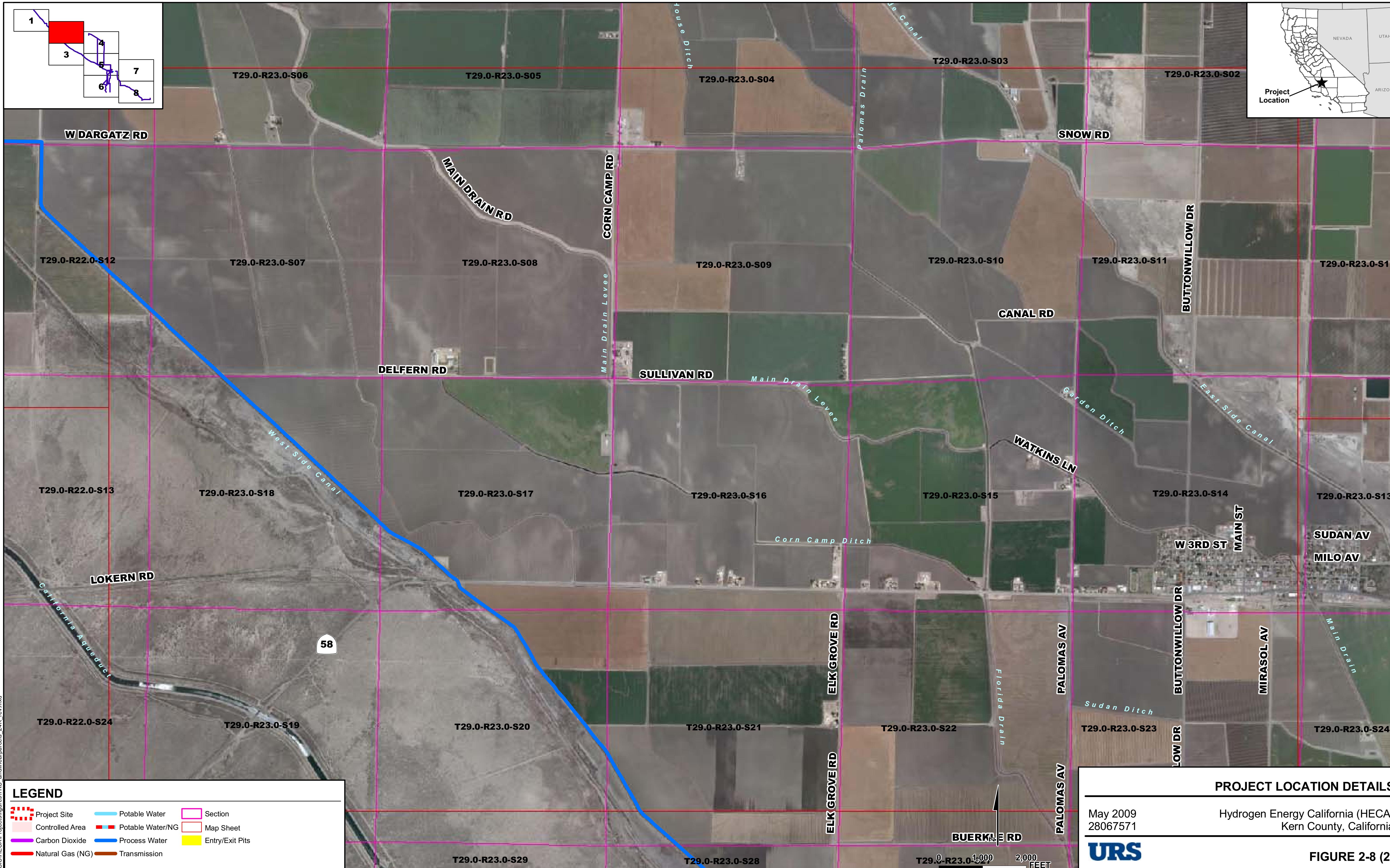


Sources: USGS (30'x60' quads: Taft 1982, Delano 1982). Created using TOPO!, ©2006 National Geographic Maps, All Rights Reserved. Kern County and State of California (proposed and approved projects).



Sources: Aerial Photos. Digital Globe, June 2008; Parcels, Roads, Crop Tyes and Existing Land Uses (derived from Kern County Assessor Use Descriptions), Kern County, 2008; Streams and Canals, US Census Bureau Tiger Data, 2000.



LEGEND

- Project Site
- Controlled Area
- Carbon Dioxide
- Natural Gas (NG)
- Potable Water
- Potable Water/NG
- Process Water
- Transmission
- Section
- Map Sheet
- Entry/Exit Pits

PROJECT LOCATION DETAILS

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FIGURE 2-8 (2)

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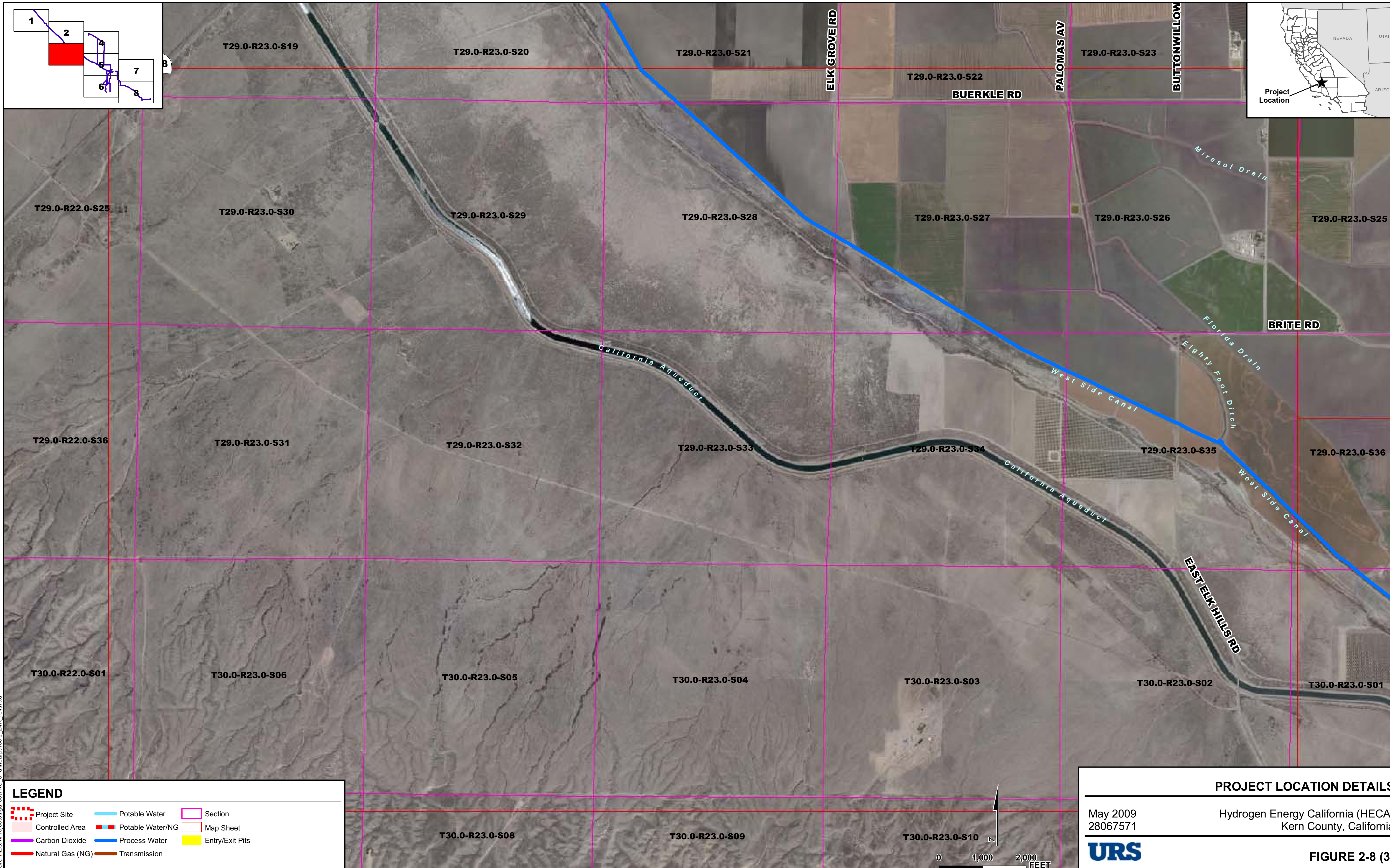
Sources: Aerial Photos. Digital Globe, June 2008; Parcels, Roads, Crop Tyes and Existing Land Uses (derived from Kern County Assessor Use Descriptions), Kern County, 2008; Streams and Canals, US Census Bureau Tiger Data, 2000.



PROJECT LOCATION DETAILS

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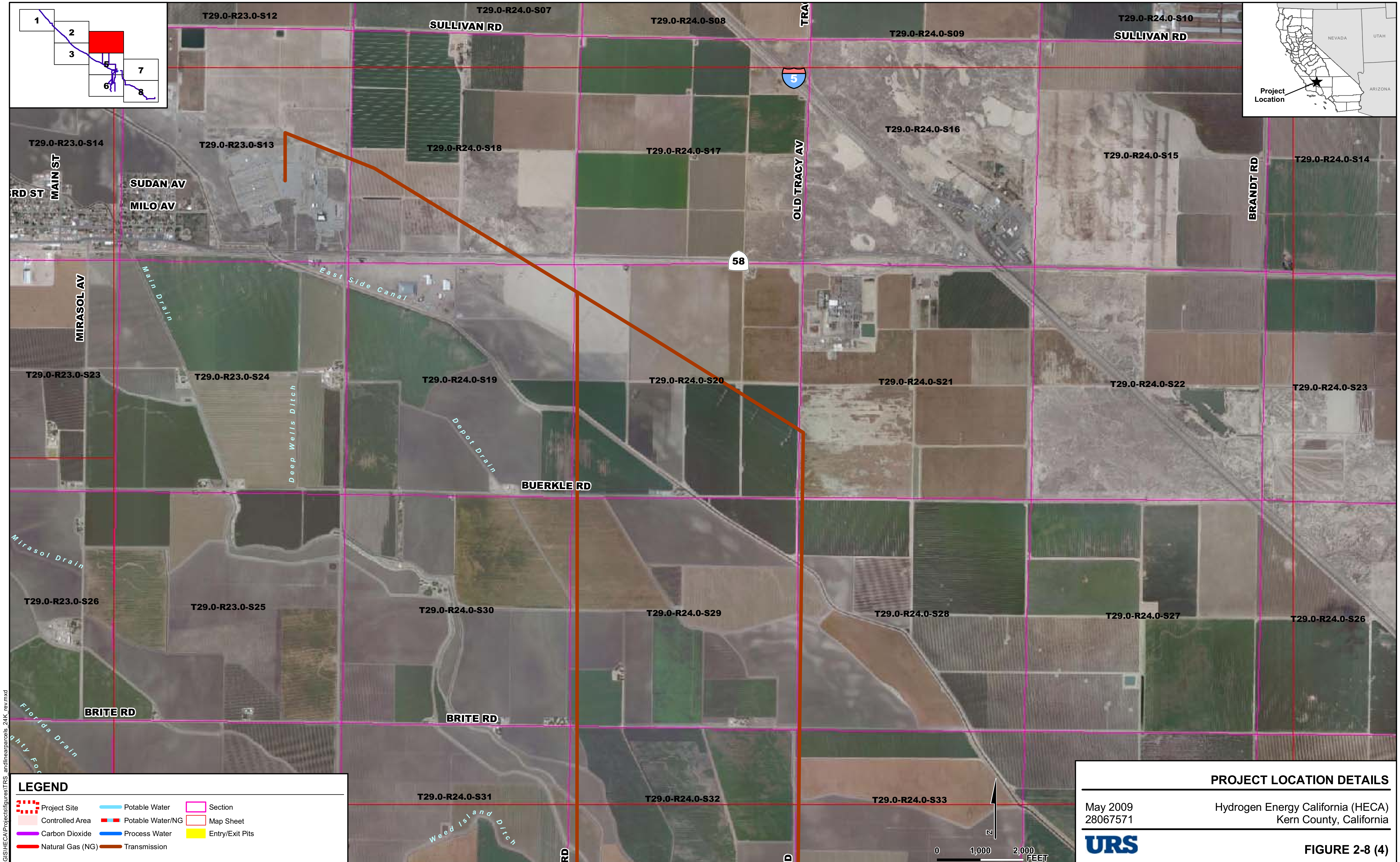
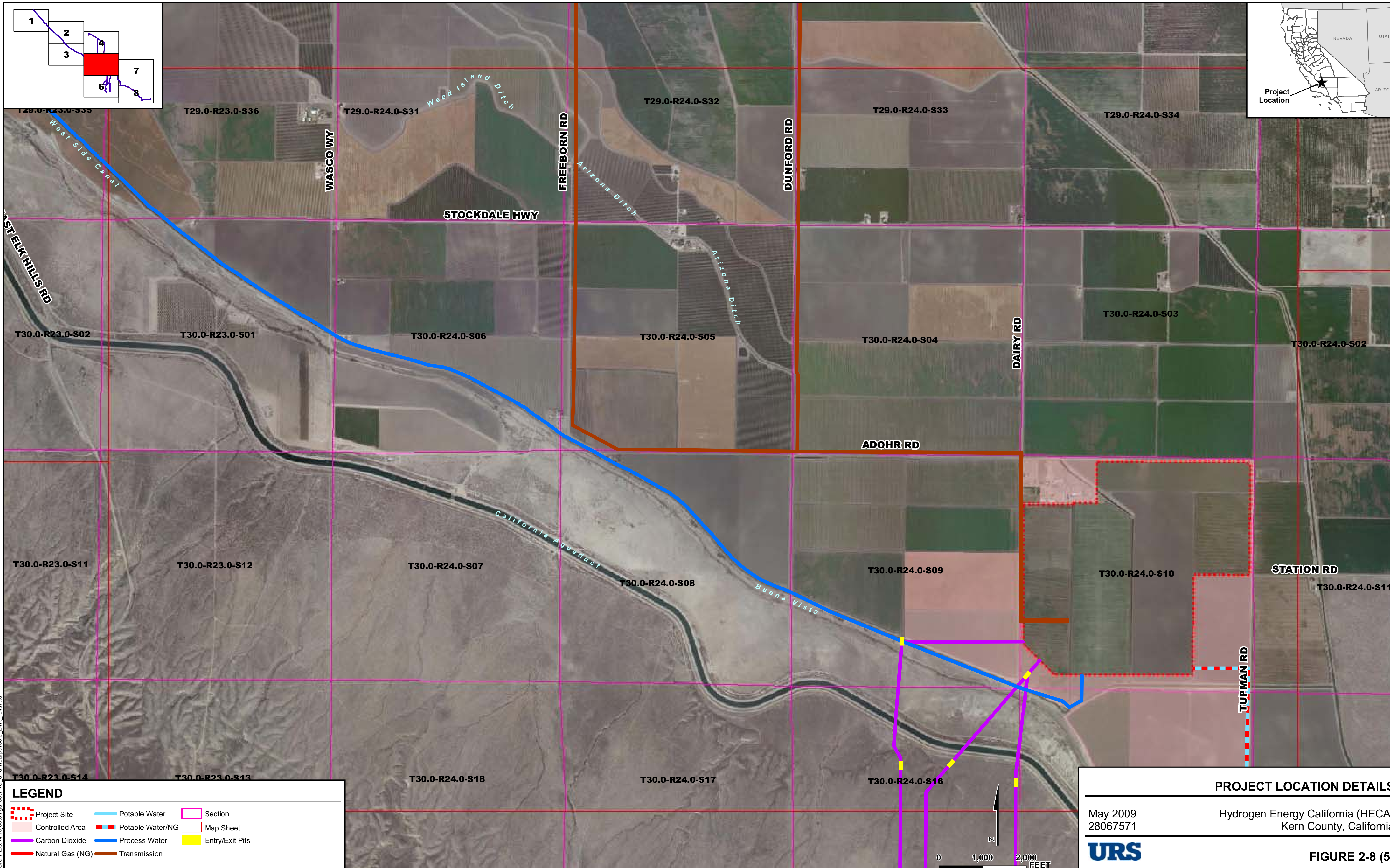
FIGURE 2-8 (3)

Sources: Aerial Photos. Digital Globe, June 2008; Parcels, Roads, Crop Tyes and Existing Land Uses (derived from Kern County Assessor Use Descriptions), Kern County, 2008; Streams and Canals, US Census Bureau Tiger Data, 2000.



Sources: Aerial Photos. Digital Globe, June 2008; Parcels, Roads, Crop Tyes and Existing Land Uses (derived from Kern County Assessor Use Descriptions), Kern County, 2008; Streams and Canals, US Census Bureau Tiger Data, 2000.



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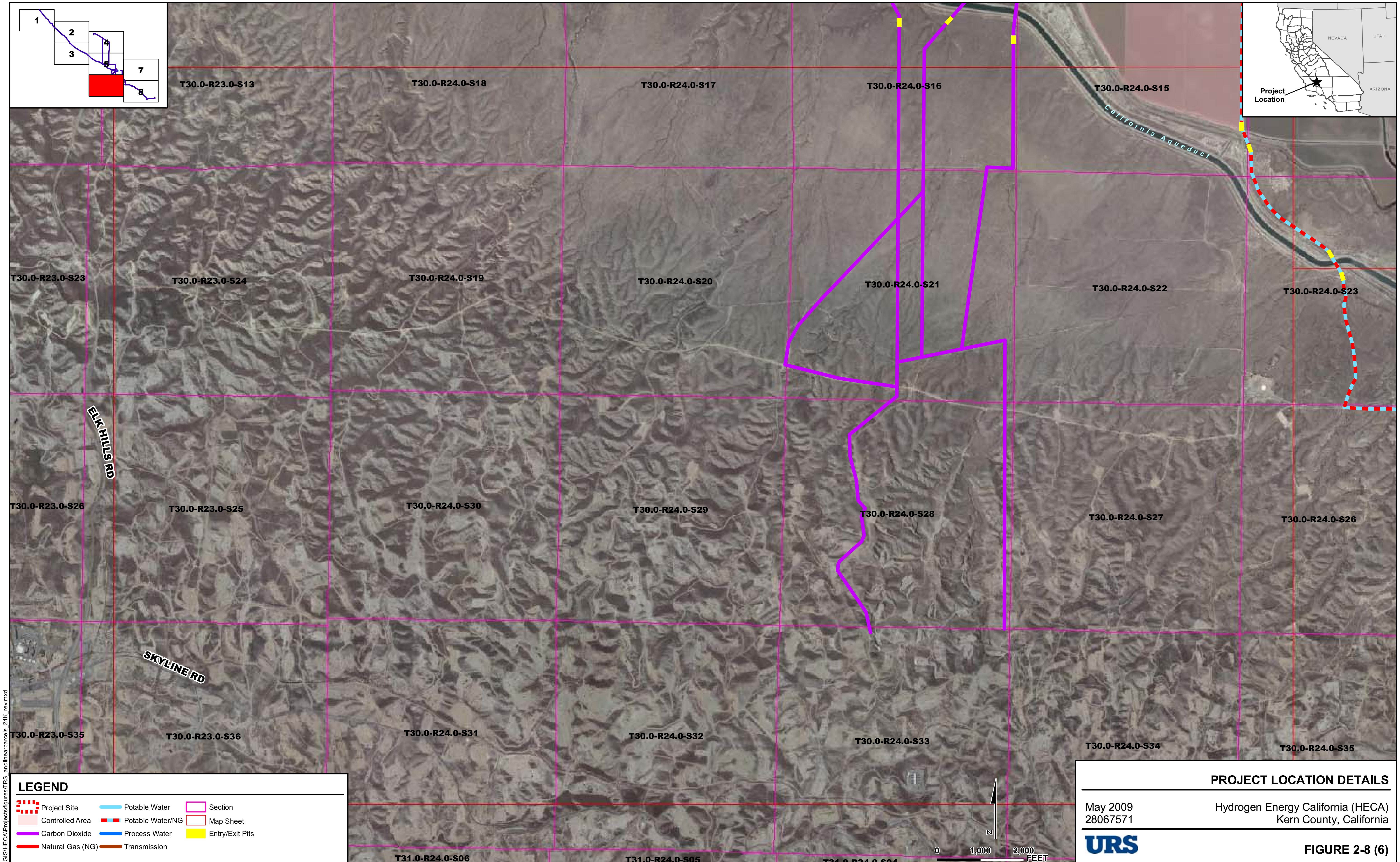
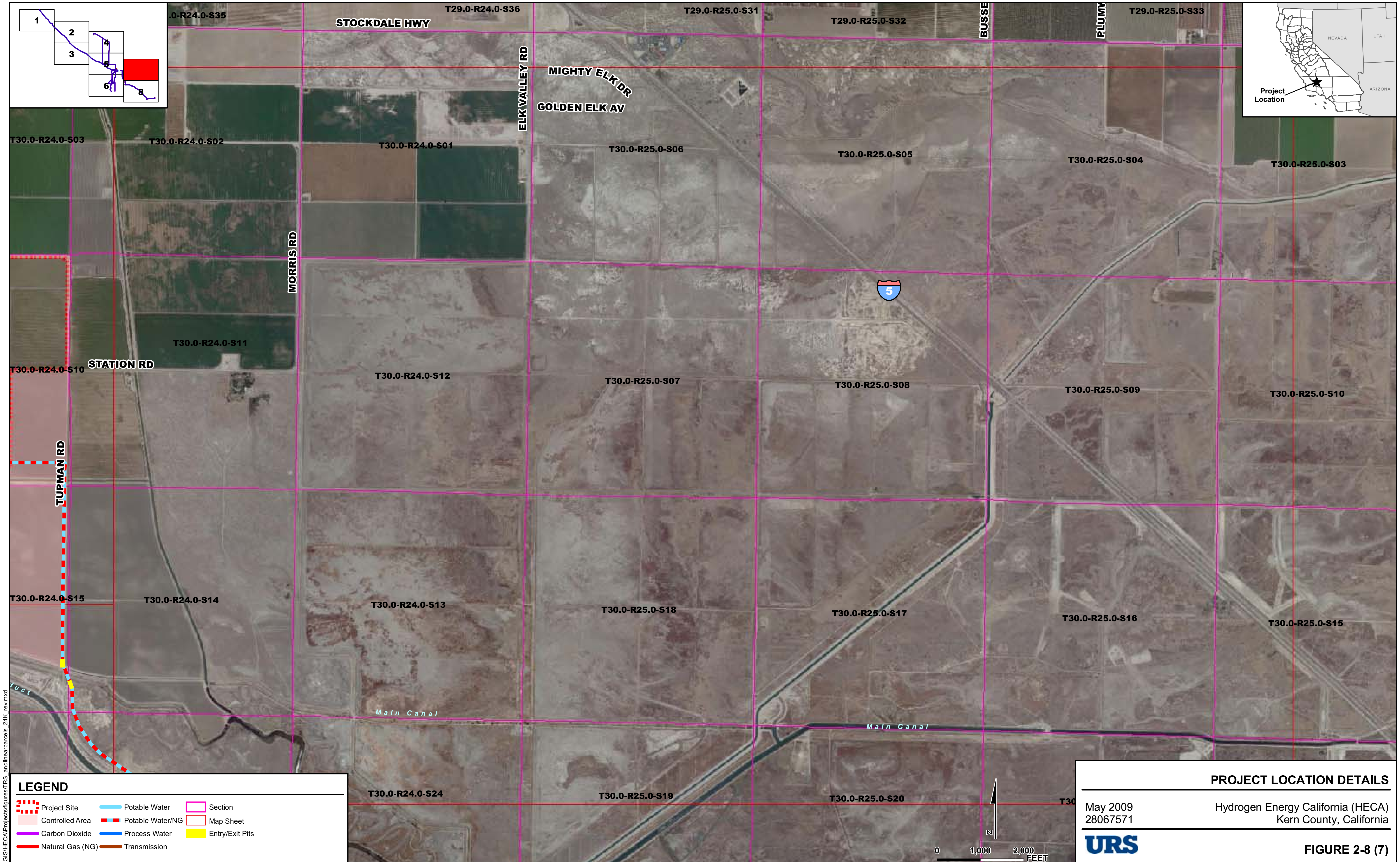
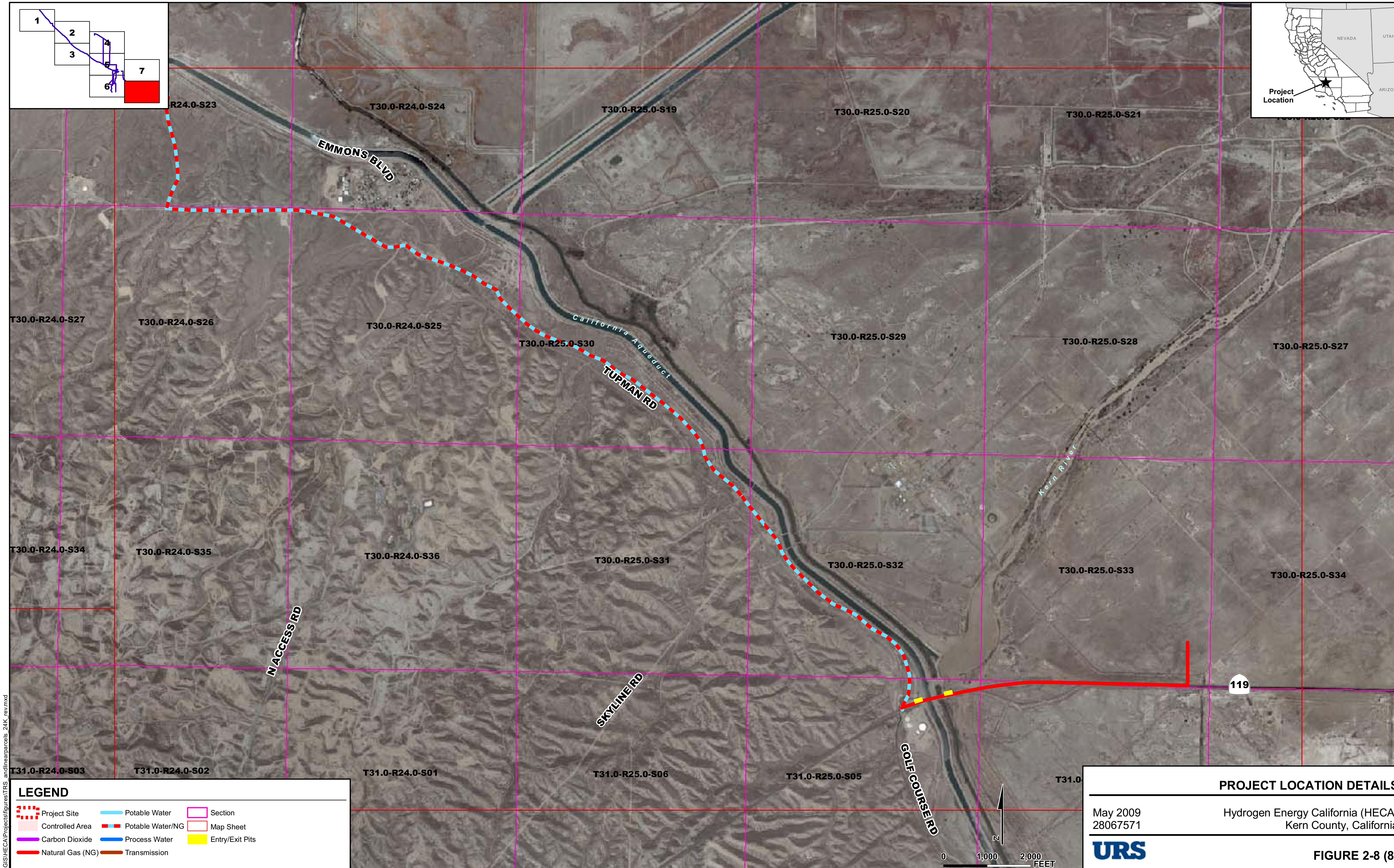
Sources: Aerial Photos. Digital Globe, June 2008; Parcels, Roads, Crop Tyes and Existing Land Uses (derived from Kern County Assessor Use Descriptions), Kern County, 2008; Streams and Canals, US Census Bureau Tiger Data, 2000.



Sources: Aerial Photos. Digital Globe, June 2008; Parcels, Roads, Crop Tyes and Existing Land Uses (derived from Kern County Assessor Use Descriptions), Kern County, 2008; Streams and Canals, US Census Bureau Tiger Data, 2000.



Sources: Aerial Photos. Digital Globe, June 2008; Parcels, Roads, Crop Tyes and Existing Land Uses (derived from Kern County Assessor Use Descriptions), Kern County, 2008; Streams and Canals, US Census Bureau Tiger Data, 2000.



PROJECT LOCATION DETAILS

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Hydrogen Energy California (HECA)
Kern County, California

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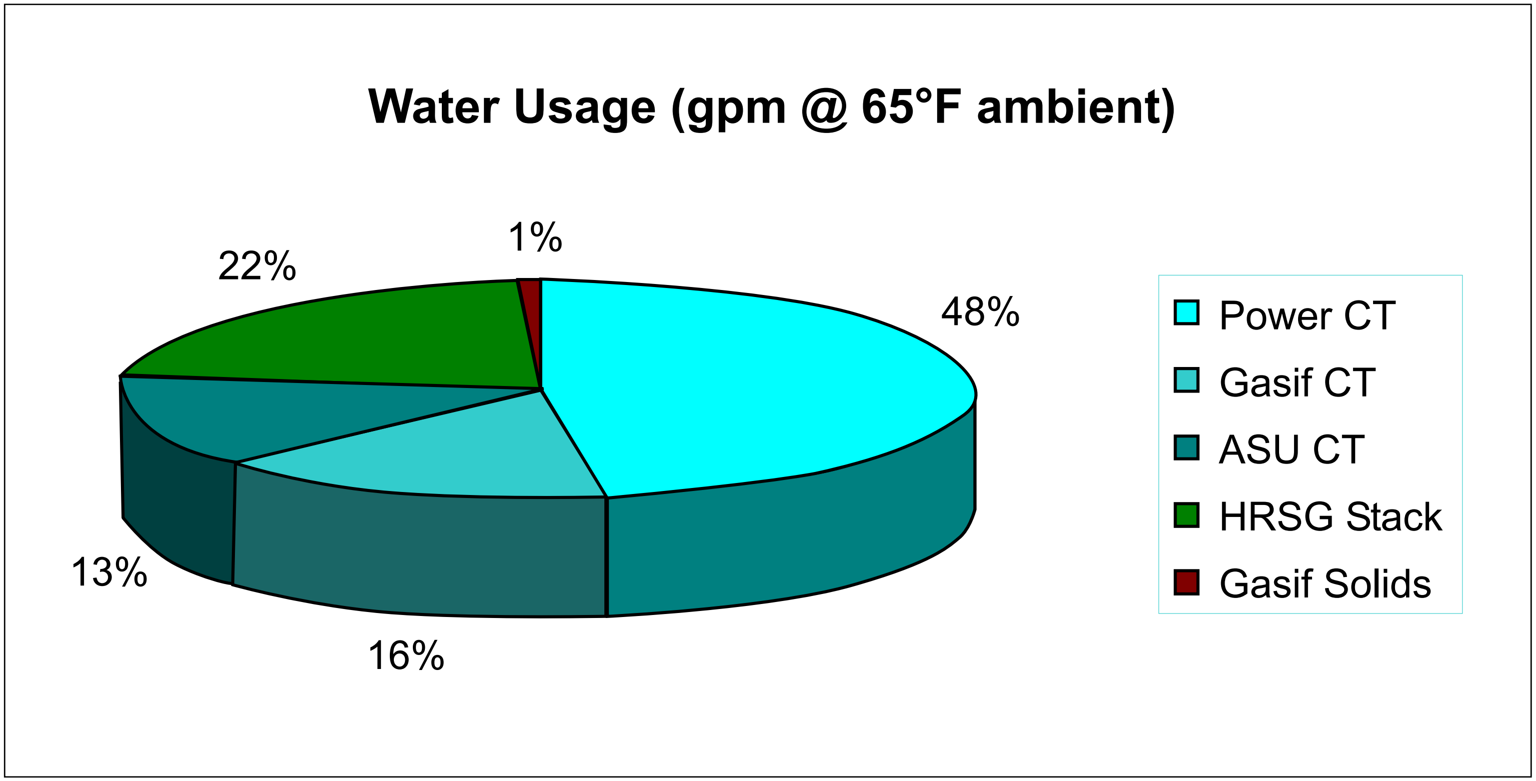
FIGURE 2-8 (8)

Sources: Aerial Photos. Digital Globe, June 2008; Parcels, Roads, Crop Tyes and Existing Land Uses (derived from Kern County Assessor Use Descriptions), Kern County, 2008; Streams and Canals, US Census Bureau Tiger Data, 2000.



WATER USAGE

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Kern County, California

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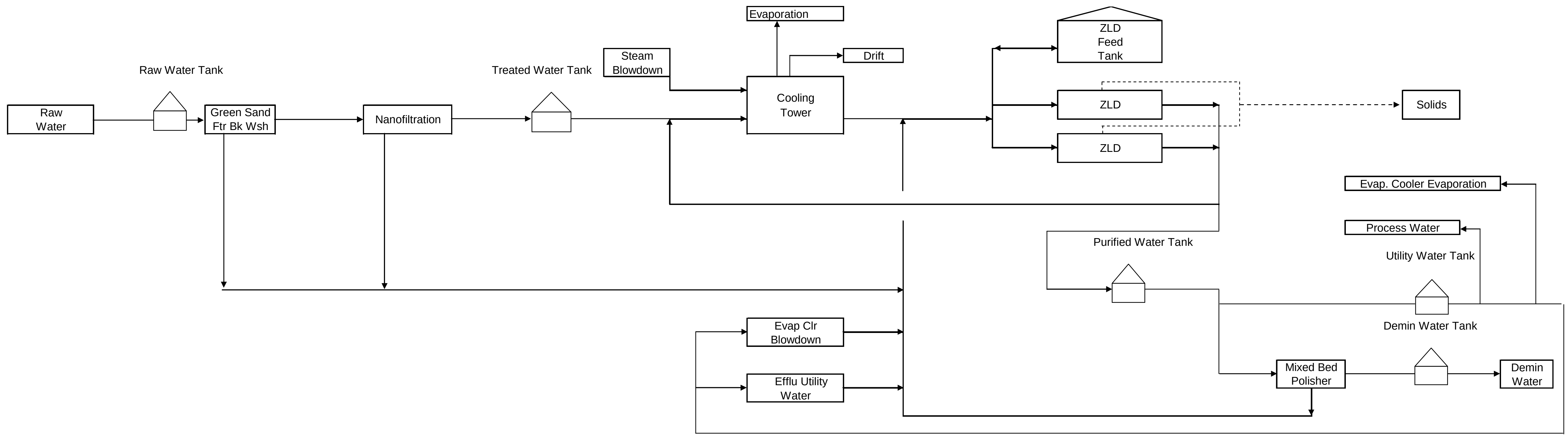
FIGURE 2-9



Source:
Fluor; Hydrogen Energy California, Kern County Power Project;
Water Use & Recovery System Diagram;
Drawing No: A3RW-PFD-25-013C, Rev. 0 (04/08/09)

WATER USE AND RECOVERY SYSTEM DIAGRAM

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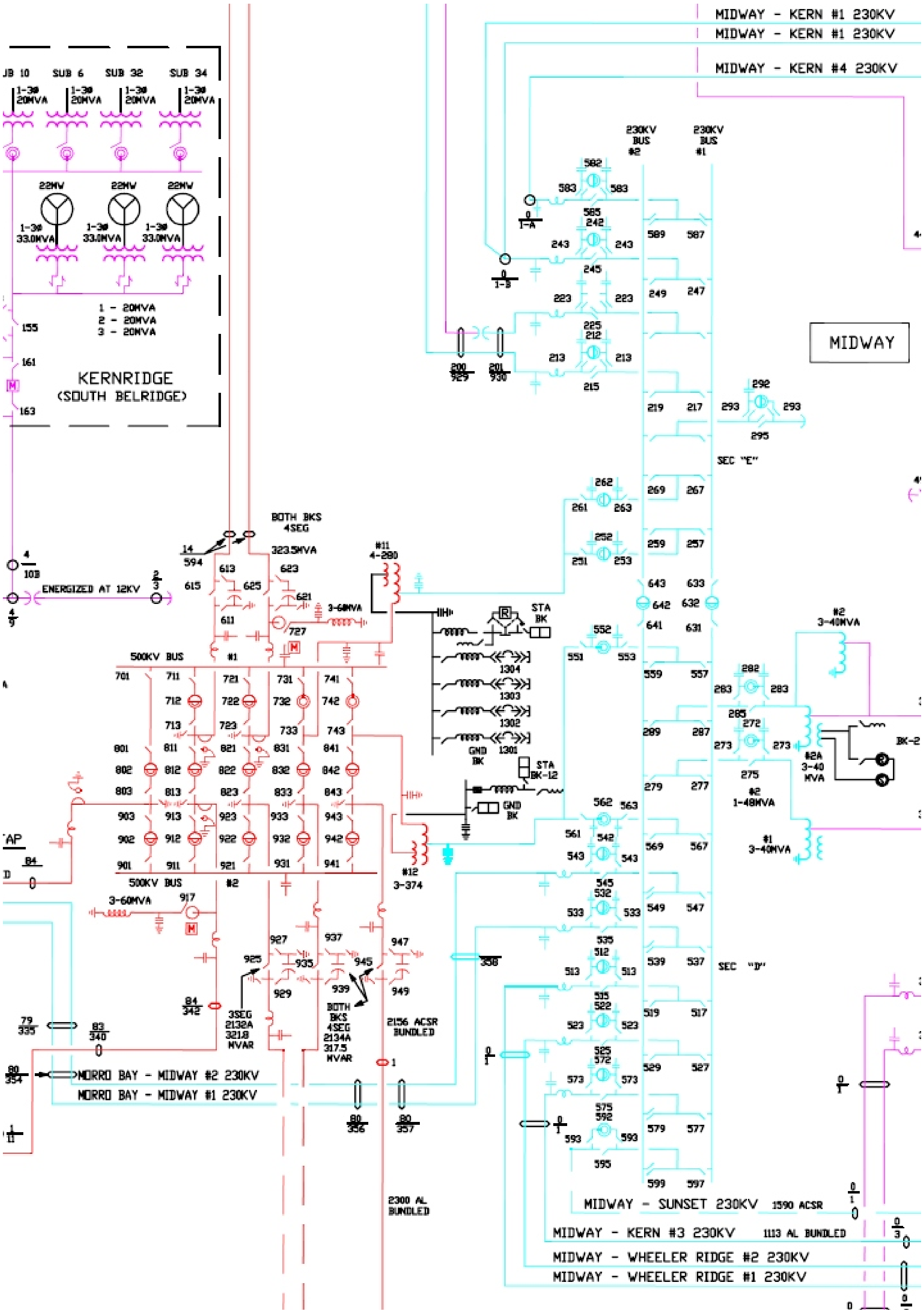
FIGURE 2-10



OVERALL SINGLE LINE DIAGRAM

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FIGURE 2-11

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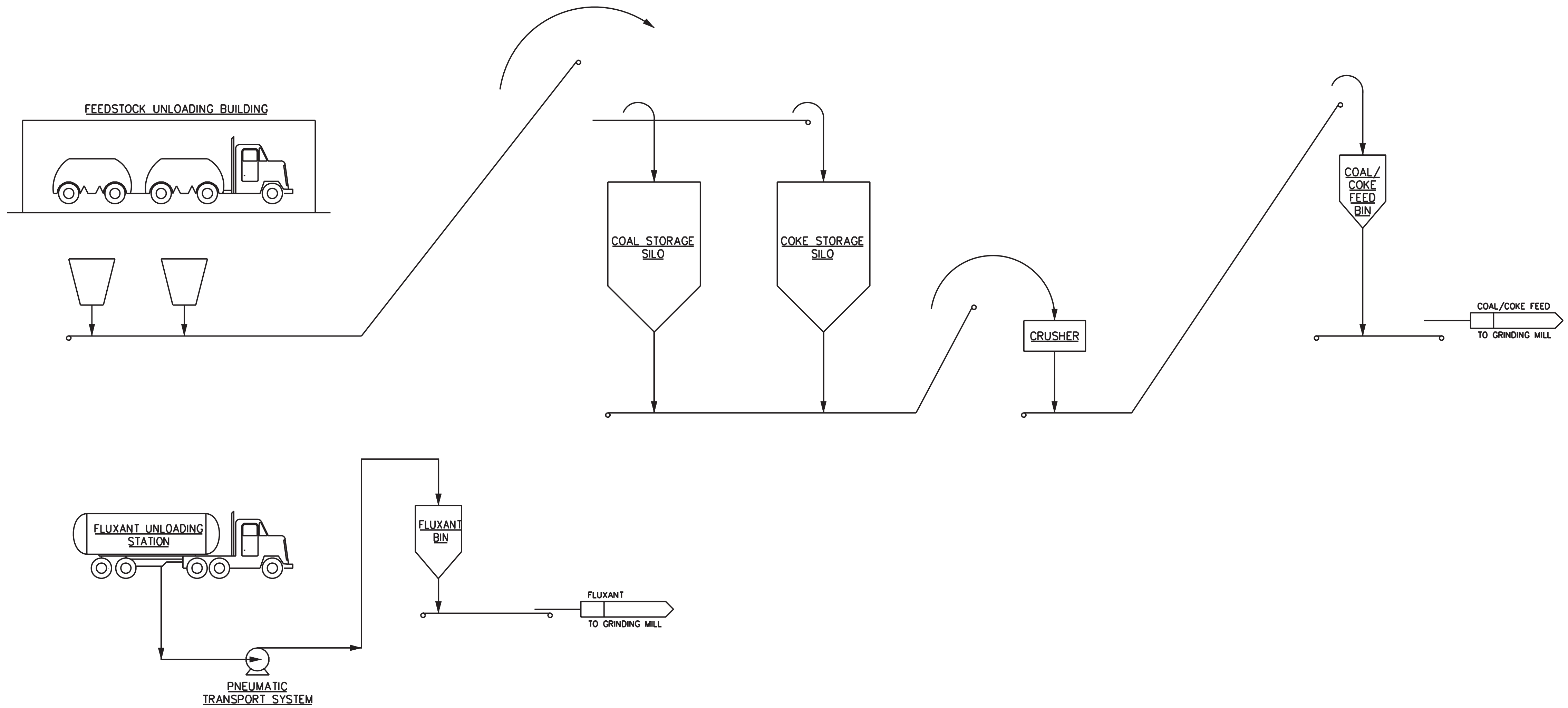

Source:
Fluor; Hydrogen Energy California, Kern County Power Project;
Flow Diagram Feedstock Handling and Storage; Drawing No: A3RW-PDF-25-003, Rev. 0 (06/04/08)

FLOW DIAGRAM
FEEDSTOCK HANDLING AND STORAGE

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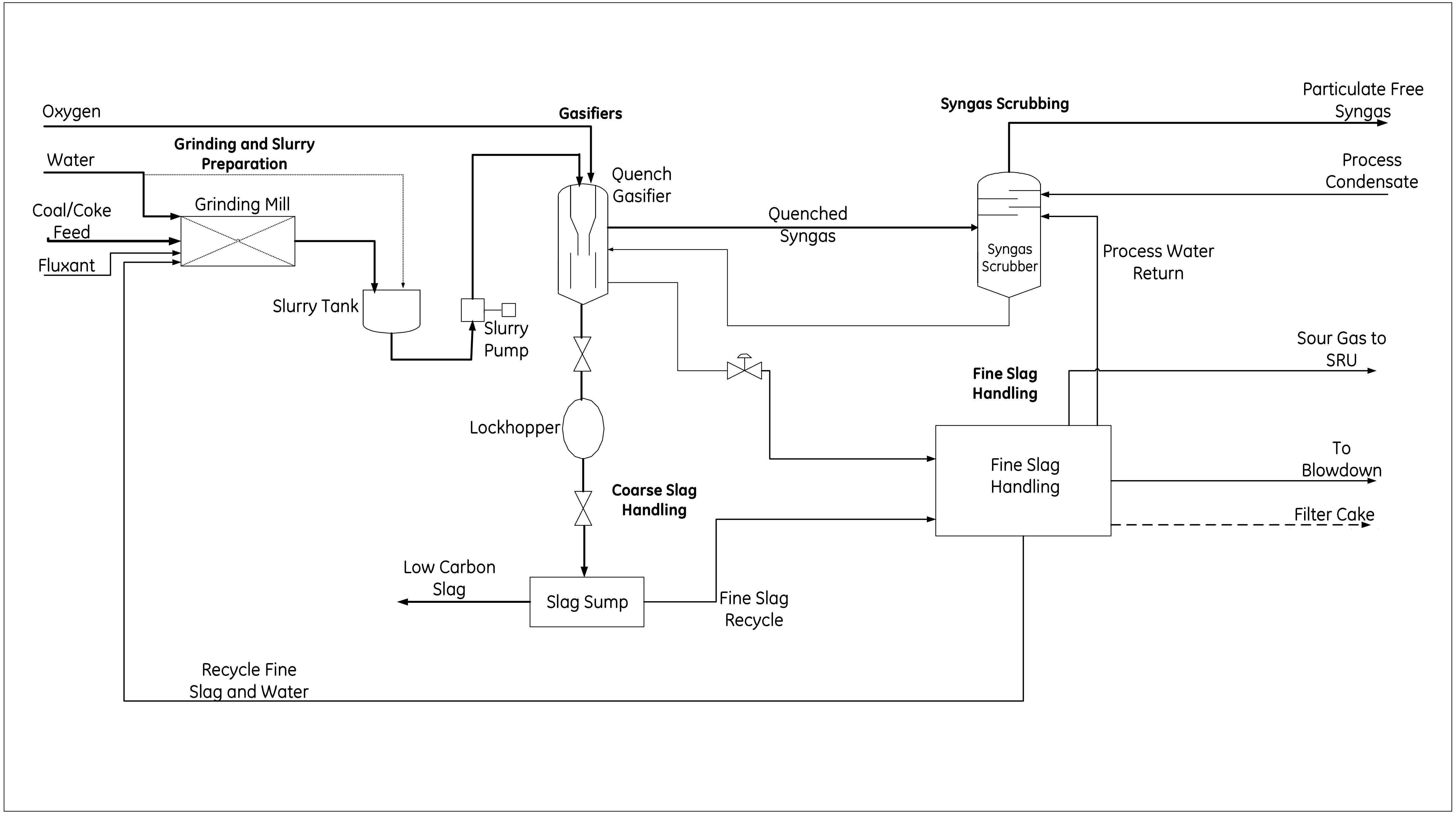
Kern County, California

FIGURE 2-12



Source:
GE Energy (USA) LLC; Hydrogen Energy California Feasibility Study;
Gasification Process Sketch for Permits; Drawing No: 334A2456, Rev. 0 (05/15/08)

GASIFICATION PROCESS SKETCH FOR PERMITS

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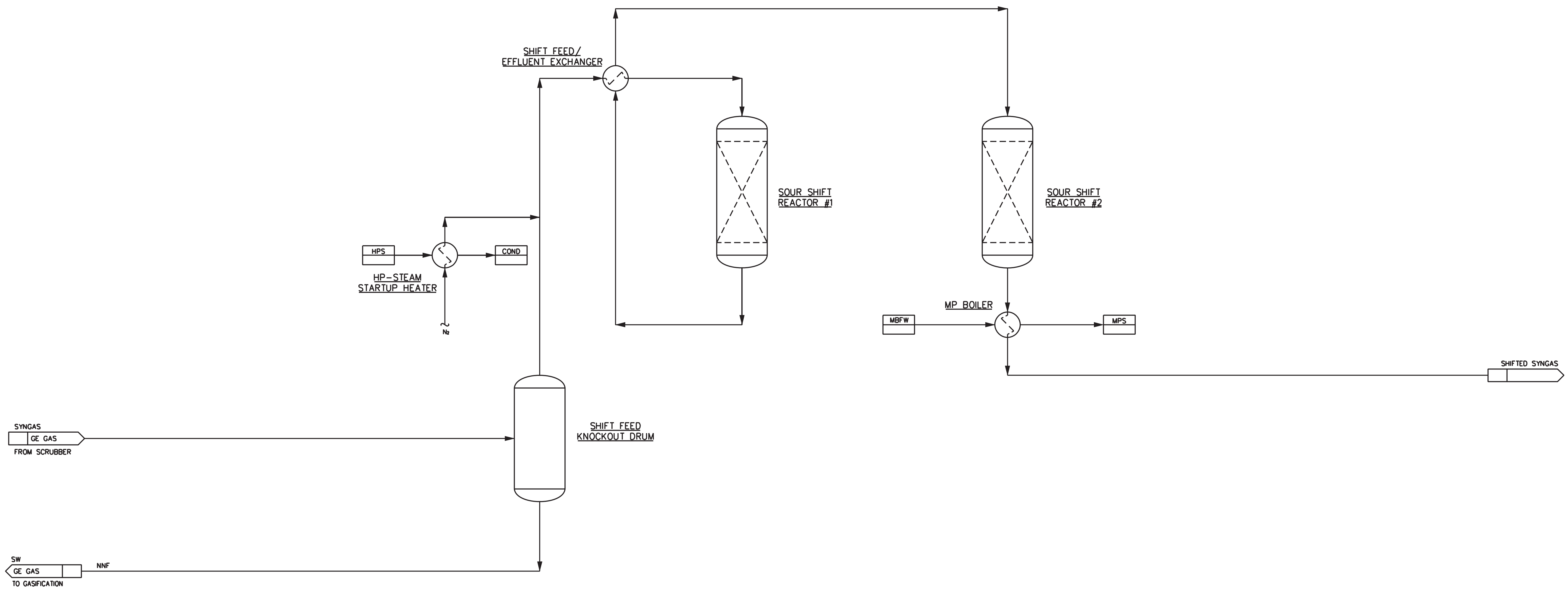
FIGURE 2-13



Source:
Fluor; Hydrogen Energy California, Kern County Power Project;
Flow Diagram, Sour Shift System; Drawing No: A3RW-PDF-24-006A, Rev. 1 (03/23/09)

FLOW DIAGRAM: SOUR SHIFT SYSTEM

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FIGURE 2-14

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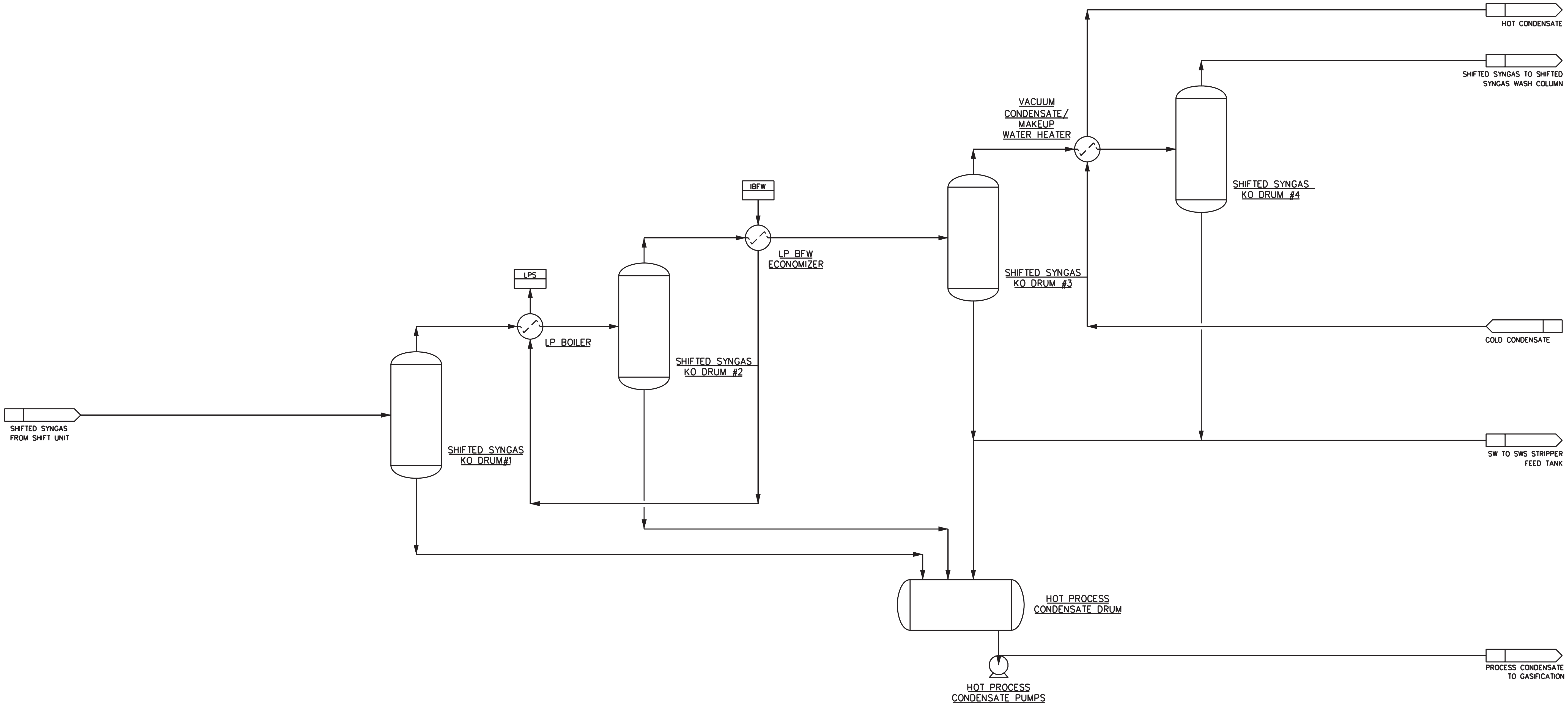

Source:
Fluor; Hydrogen Energy California, Kern County Power Project;
Flow Diagram, Low Temperature Gas Cooling (LTGC);
Drawing No: A3RW-PDF-25-006B, Rev. 1 (03/06/09)

FLOW DIAGRAM
LOW TEMPERATURE GAS COOLING

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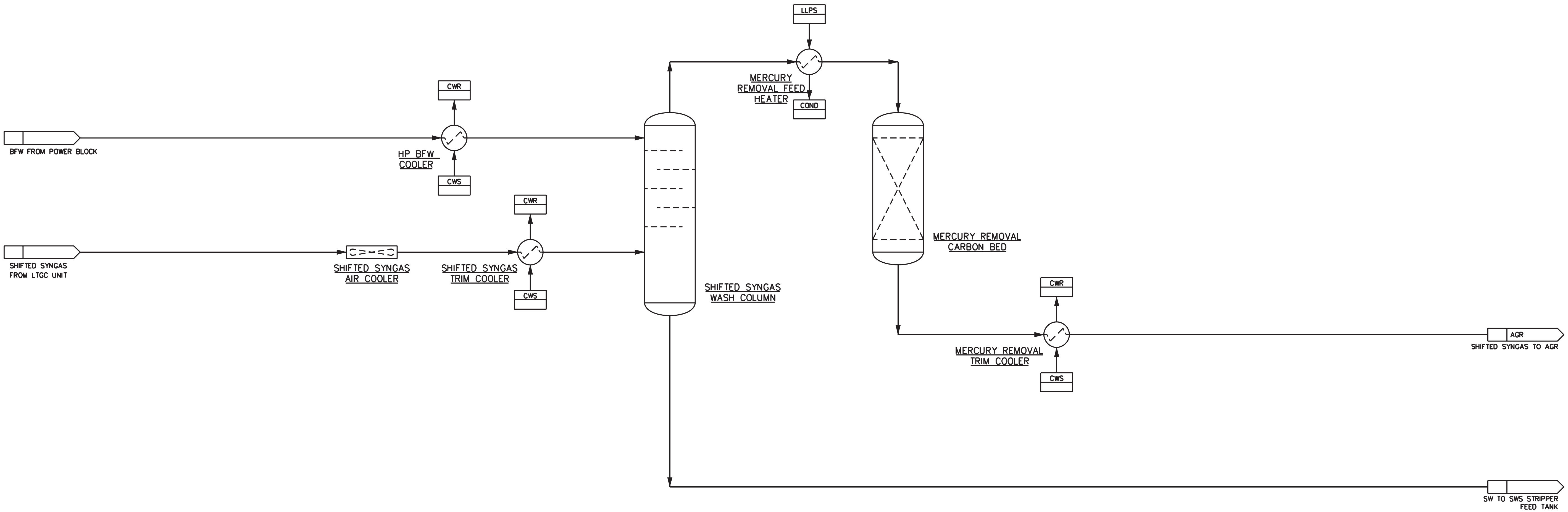
FIGURE 2-15



Source:
Fluor; Hydrogen Energy California, Kern County Power Project;
Flow Diagram, Wash Colum and Mercury Removal;
Drawing No: A3RW-PDF-25-006C, Rev. 0 (06/04/08)

FLOW DIAGRAM: WASH COLUMN AND MERCURY REMOVAL

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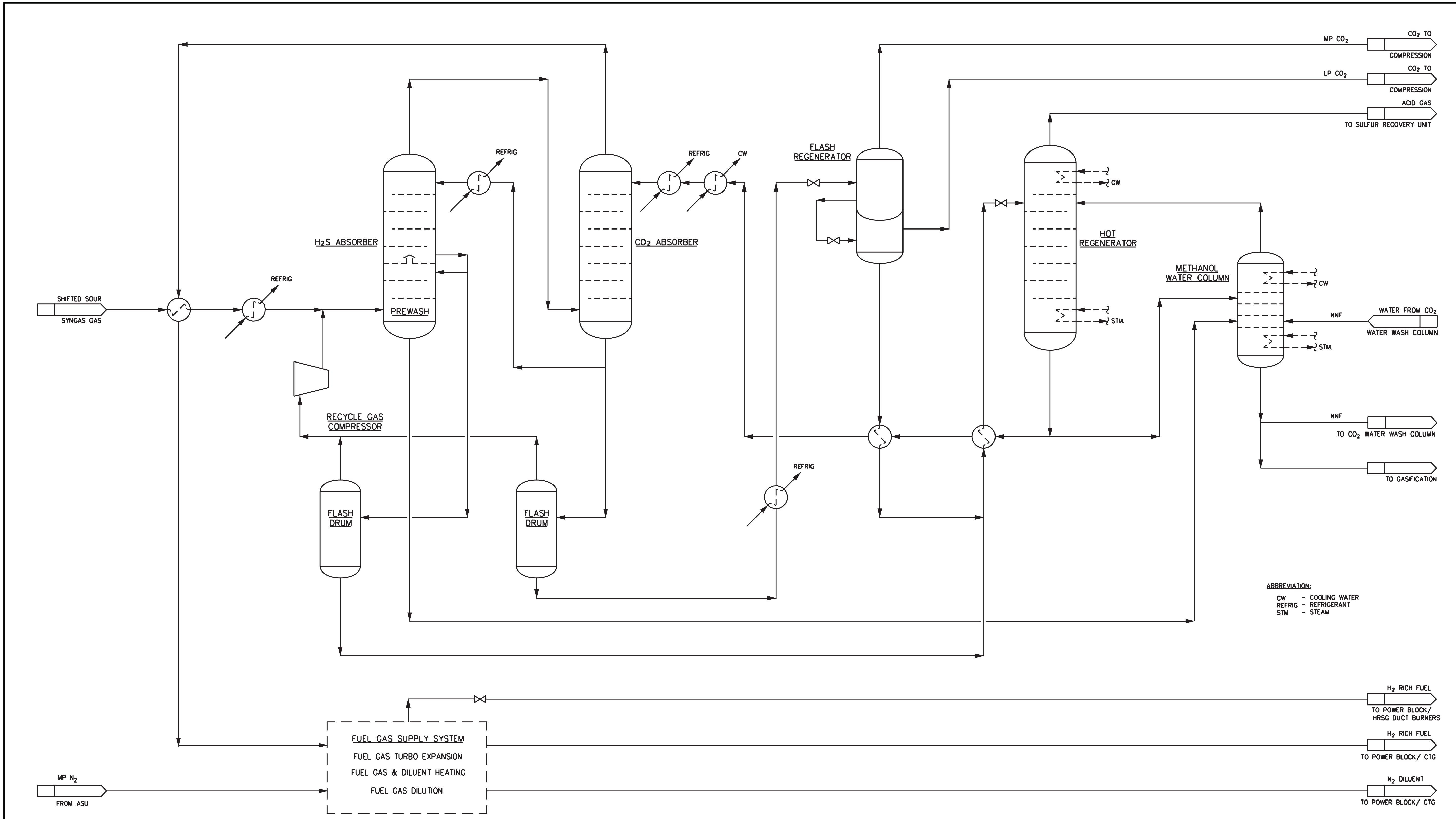
FIGURE 2-16



Source:
Fluor; Hydrogen Energy California, Kern County Power Project;
Flow Diagram, Rectisol Acid Gas Removal/Fuel Gas Supply Systems;
Drawing No: A3RW-PFD-25-007, Rev. 2 (04/13/09)

FLOW DIAGRAM
ACID GAS REMOVAL/
FUEL GAS SUPPLY SYSTEMS

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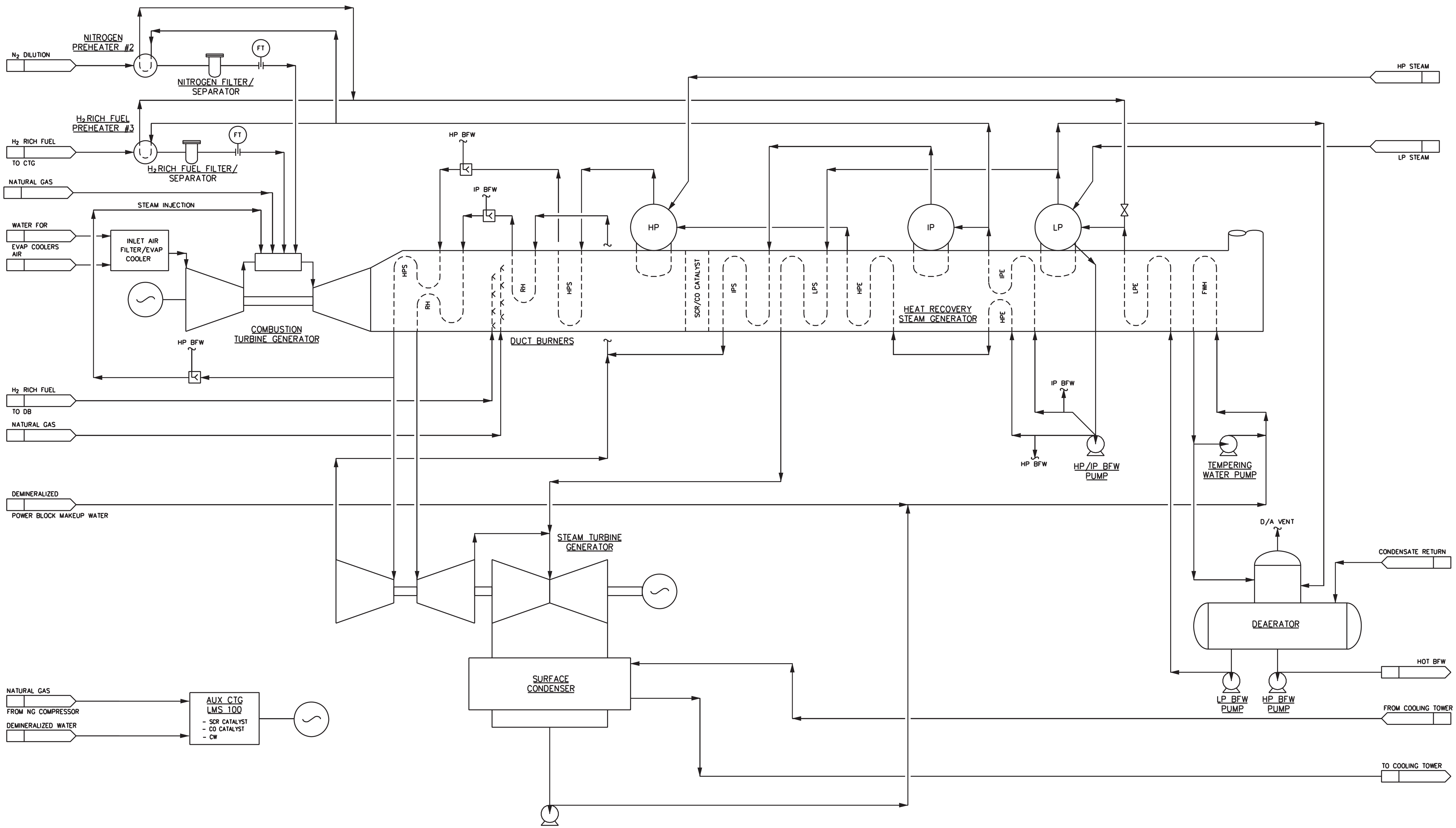
FIGURE 2-17

5/1809 vsa..T:\HECA\GRAPHICS\2.0 Project Description\2-17_rectisol acid gas.ai



Source:
Fluor; Hydrogen Energy California, Kern County Power Project;
Flow Diagram, Power Block Systems;
Drawing No: A3RW-PDF-25-010, Rev. 1 (02/09/09)

FLOW DIAGRAM
POWER BLOCK SYSTEMS

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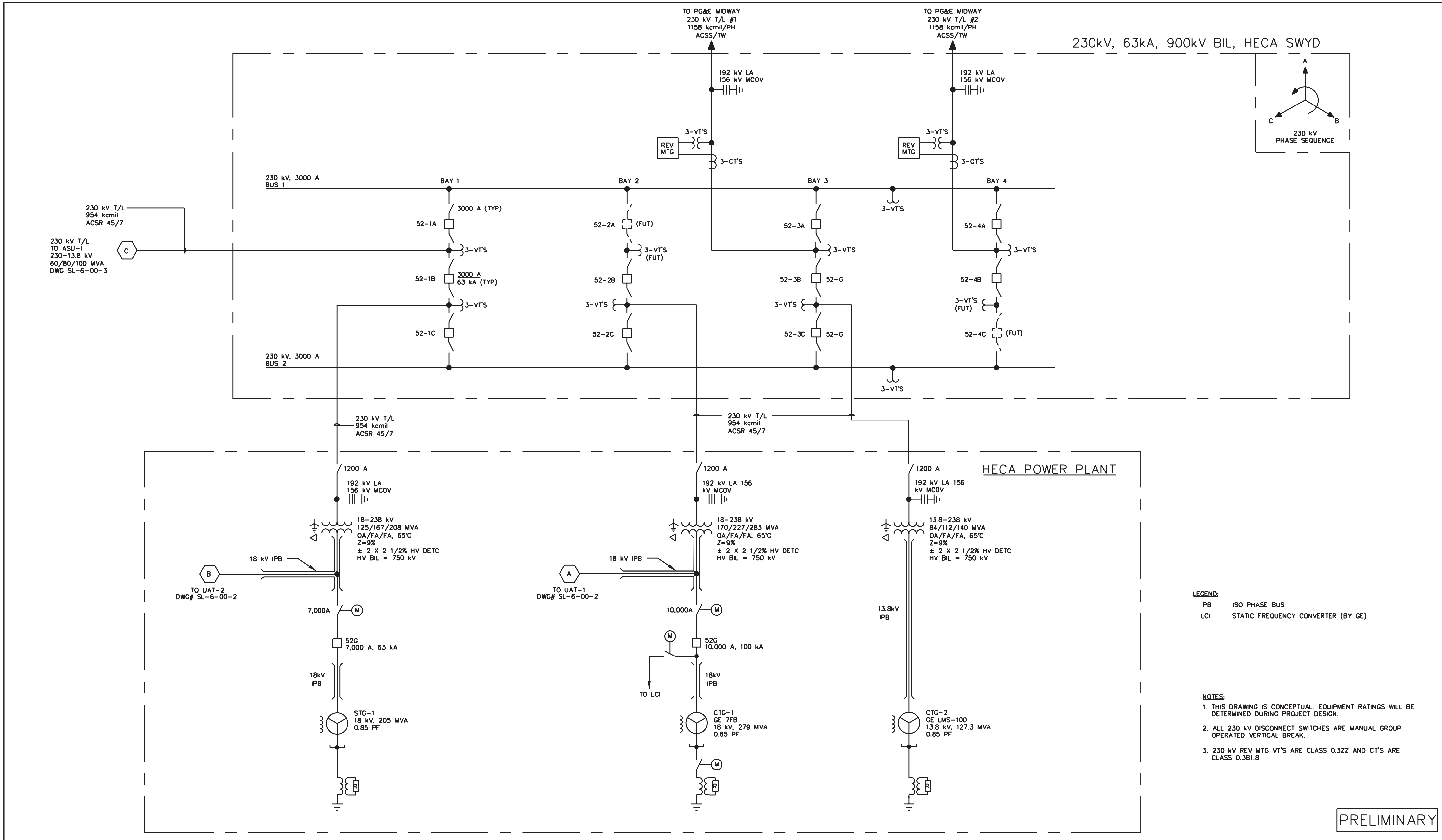
FIGURE 2-18

5/18/09 vsa..T:\HECA\GRAPHICS\2.0 Project Description\2-18_power block systems.ai



Source:
Fluor; Hydrogen Energy California, Kern County Power Project;
Electrical Overall One Line Diagram;
Drawing No: A3RW00-0-SL-6-001, Rev. 2 (01/05/09)

ELECTRICAL
OVERALL ONE-LINE DIAGRAM (1)

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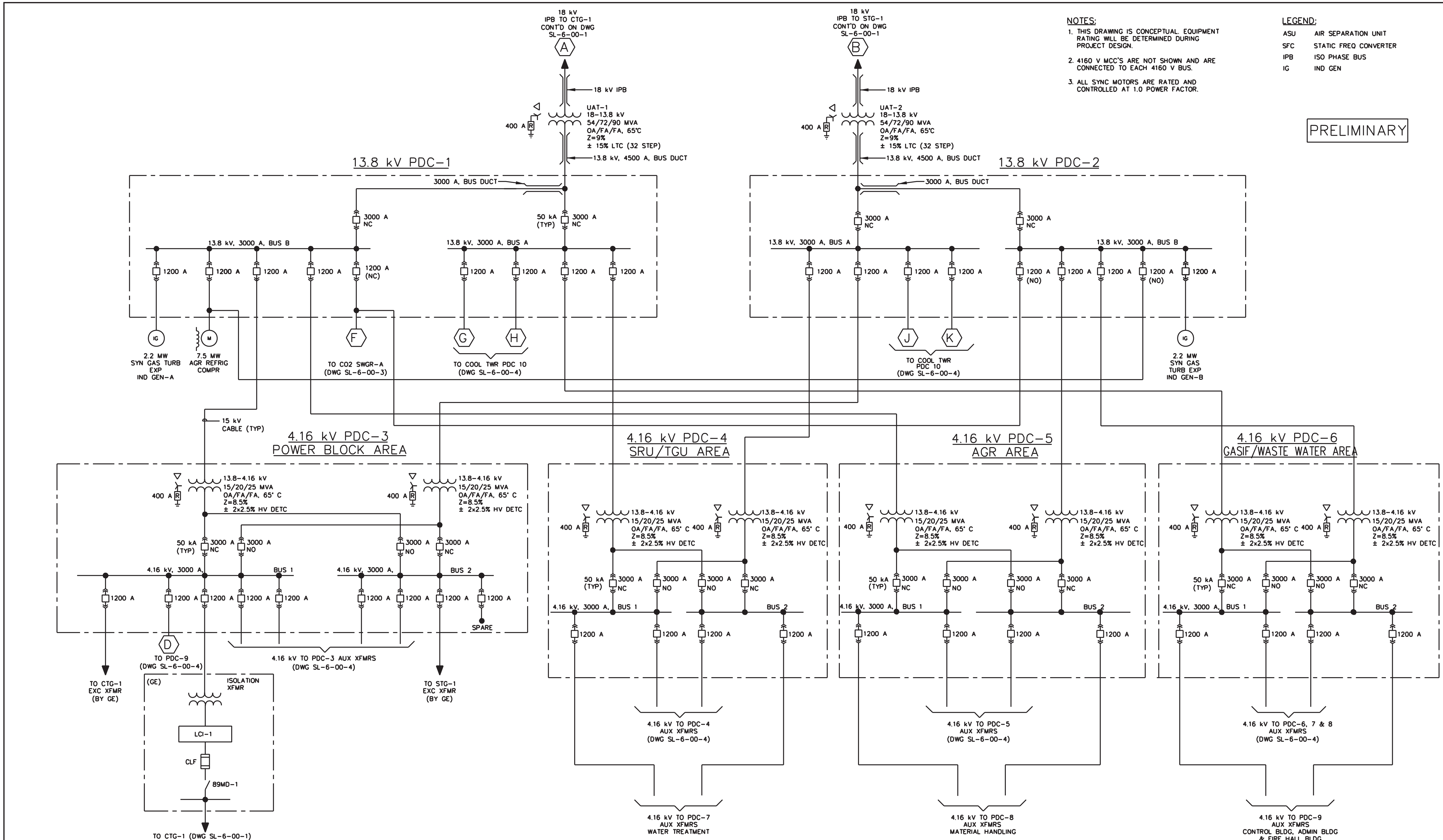
FIGURE 2-19



Source:
Fluor; Hydrogen Energy California, Kern County Power Project;
Electrical Overall One Line Diagram;
Drawing No: A3RW00-0-SL-6-002, Rev. 2 (01/05/09)

ELECTRICAL
OVERALL ONE-LINE DIAGRAM (2)

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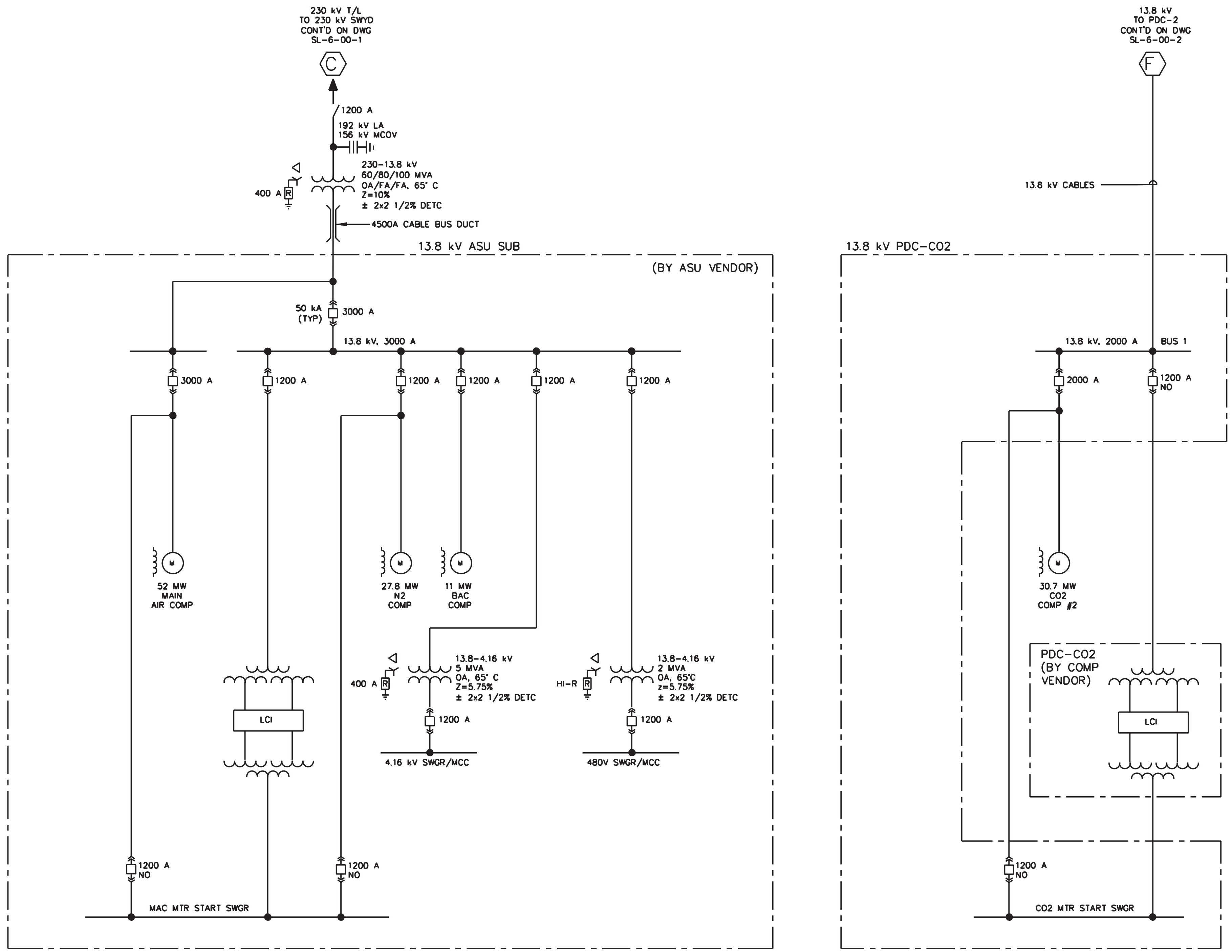
FIGURE 2-20

5/20/09 vsa..T:\HECA\GRAPHICS\2.0 Project Description\2-20_elec overall 1-line_2.ai



NOTES:
1. THIS DRAWING IS CONCEPTUAL. EQUIPMENT RATING WILL BE DETERMINED DURING PROJECT DESIGN.
2. ALL SYNC MOTORS ARE RATED AND CONTROLLED AT 1.0 POWER FACTOR.

PRELIMINARY

Source:
Fluor; Hydrogen Energy California, Kern County Power Project;
Electrical Overall One Line Diagram;
Drawing No: A3RW00-0-SL-6-003, Rev. 0 (06/04/08)

ELECTRICAL
OVERALL ONE-LINE DIAGRAM (3)

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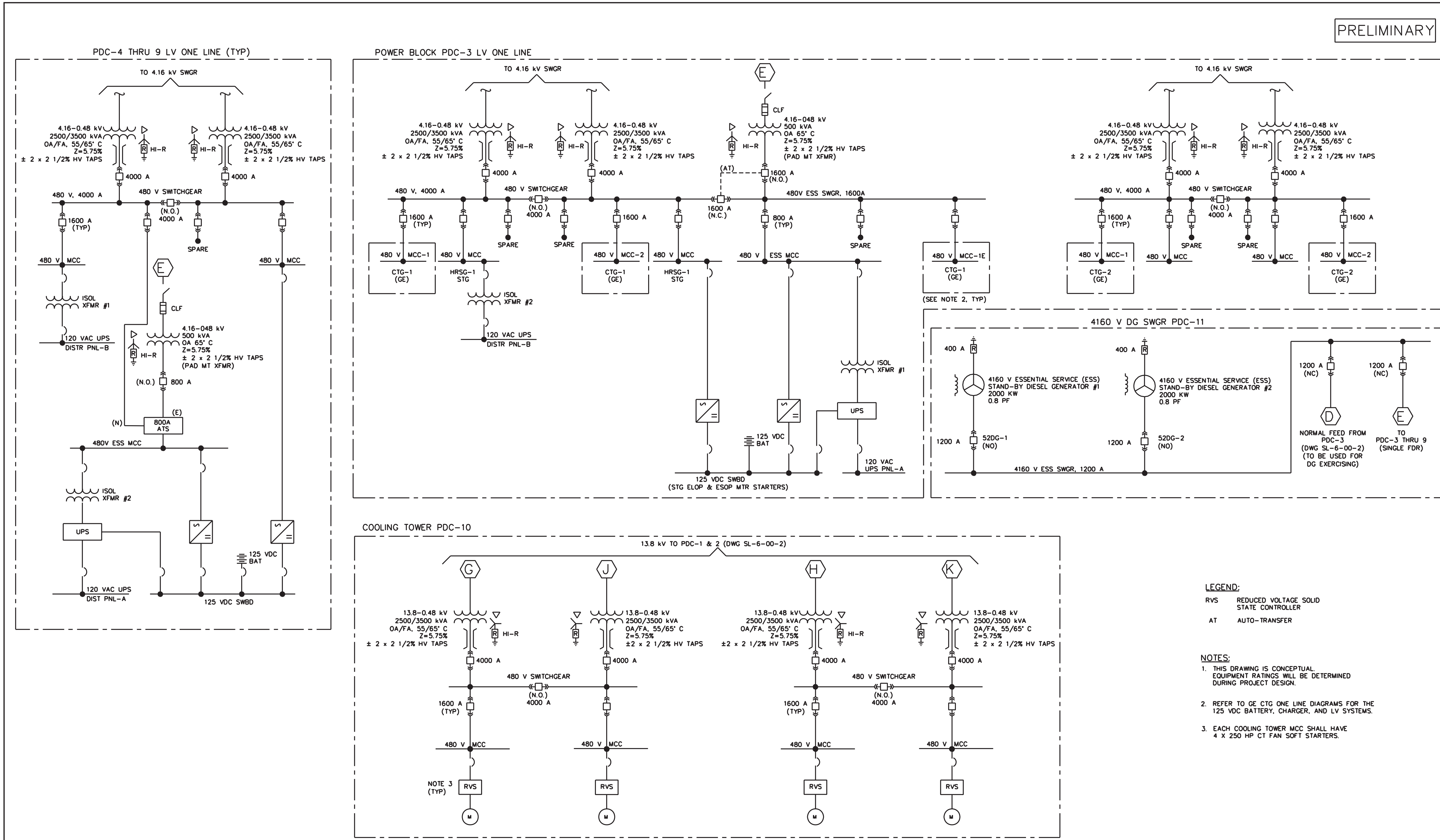
FIGURE 2-21

5/20/09 vsa..T:\HECA\GRAPHICS\2.0 Project Description\2-21_elec overall 1-line_3.ai



Source:
Fluor; Hydrogen Energy California, Kern County Power Project;
Electrical Overall One Line Diagram;
Drawing No: A3RW00-0-SL-6-004, Rev. 2 (01/05/09)

ELECTRICAL
OVERALL ONE-LINE DIAGRAM (4)

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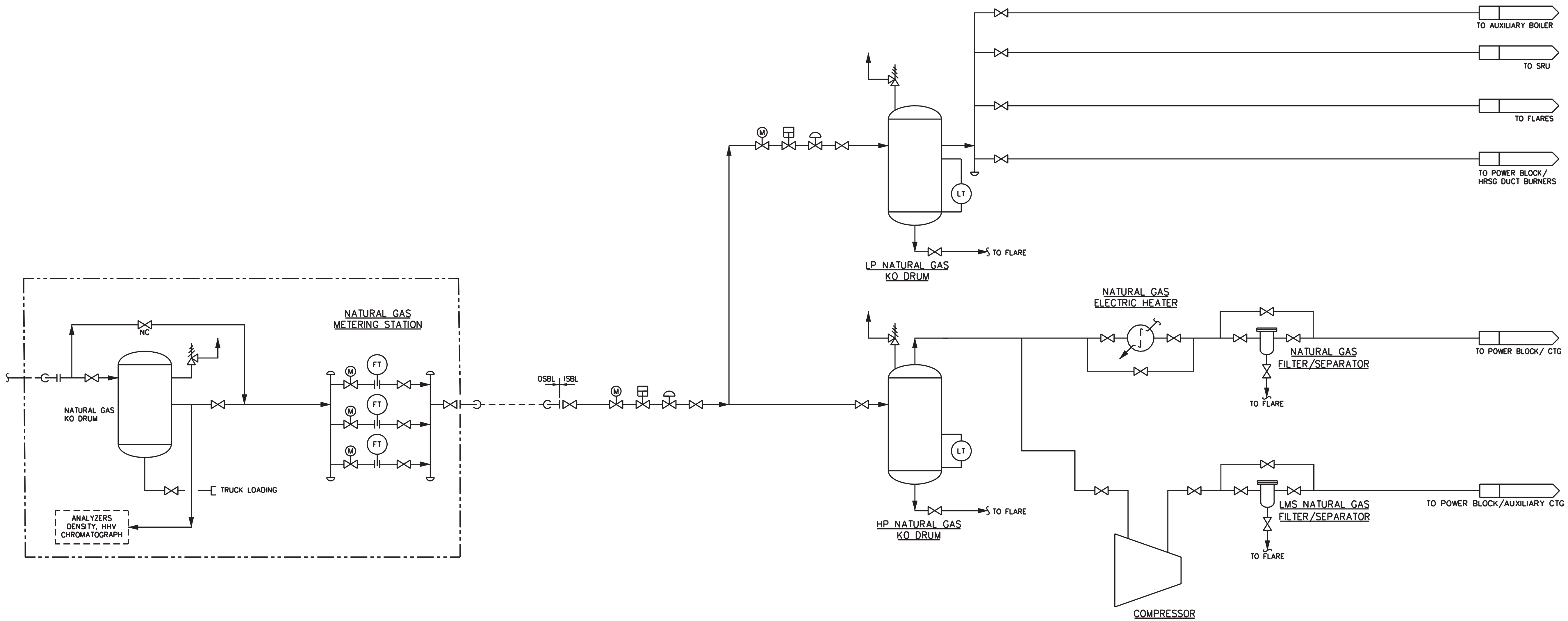
FIGURE 2-22



Source:
Fluor; Hydrogen Energy California, Kern County Power Project;
Flow Diagram, Natural Gas System;
Drawing No: A3RW-PFD-25-019, Rev. 2 (04/13/09)

FLOW DIAGRAM
NATURAL GAS SYSTEM

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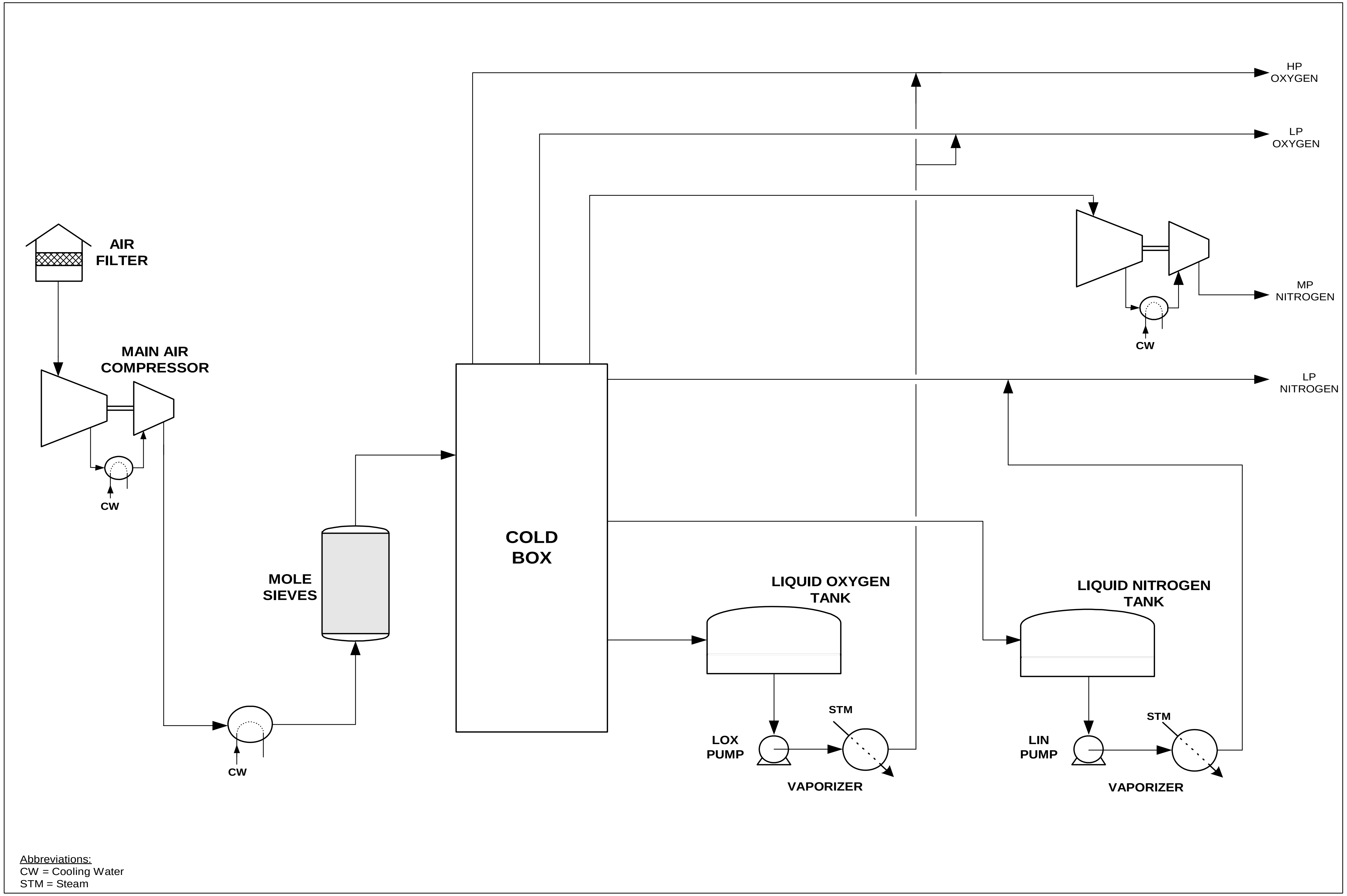
FIGURE 2-23



Source:
Fluor; Hydrogen Energy California, Kern County Power Project;
Air Separation Unit; Drawing No: A3RW-PDF-25-024 (06/04/08)

AIR SEPARATION UNIT

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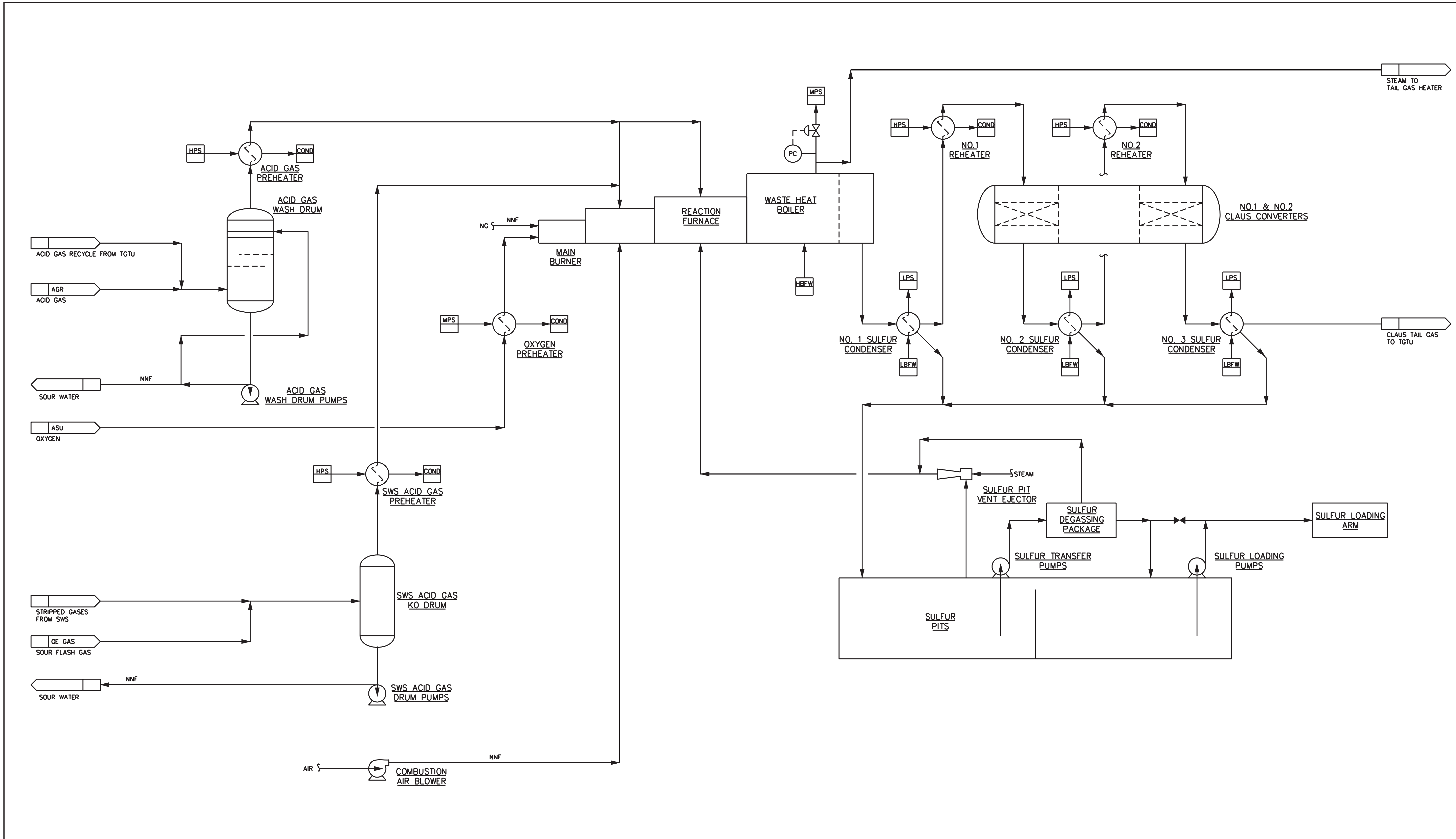
FIGURE 2-24

5/20/09 vsa..T:\HECA\GRAPHICS\2.0 Project Description\2-24_air separation.ai



Source:
Fluor; Hydrogen Energy California, Kern County Power Project;
Flow Diagram, Sulfur Recovery Unit;
Drawing No: A3RW-PDF-25-008, Rev. 2 (06/04/08)

FLOW DIAGRAM
SULFUR RECOVERY UNIT

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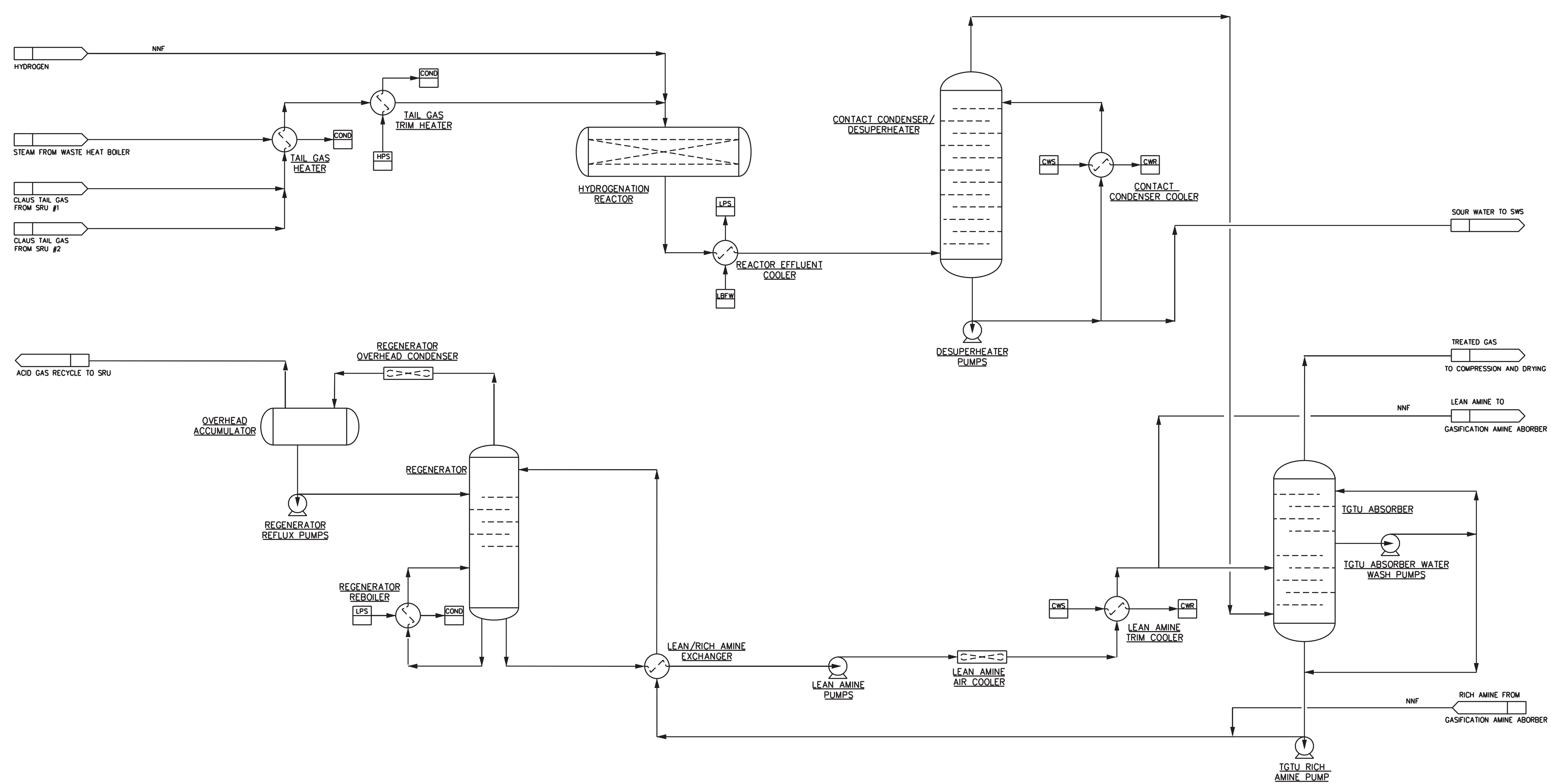
FIGURE 2-25



Source:
Fluor; Hydrogen Energy California, Kern County Power Project;
Flow Diagram, Tail Gas Treating Unit;
Drawing No: A3RW-PFD-25-009, Rev. 2 (04/13/09)

FLOW DIAGRAM
TAIL GAS TREATING UNIT

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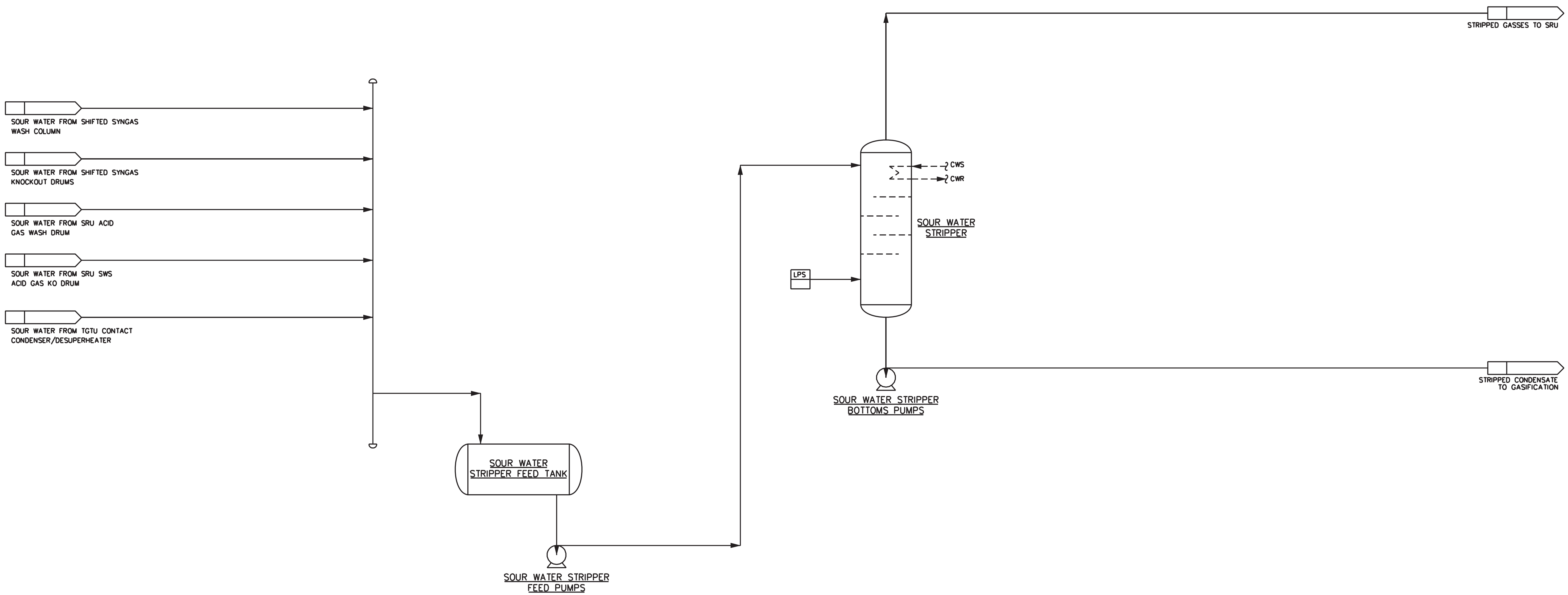
FIGURE 2-26

5/20/09 vsa..T:\HECA\GRAPHICS\2.0 Project Description\2-26_tailgas.ai



Source:
Fluor; Hydrogen Energy California, Kern County Power Project;
Flow Diagram, Sour Water Stripper;
Drawing No: A3RW-PDF-25-012, Rev. 1 (03/23/09)

FLOW DIAGRAM
SOUR WATER STRIPPER

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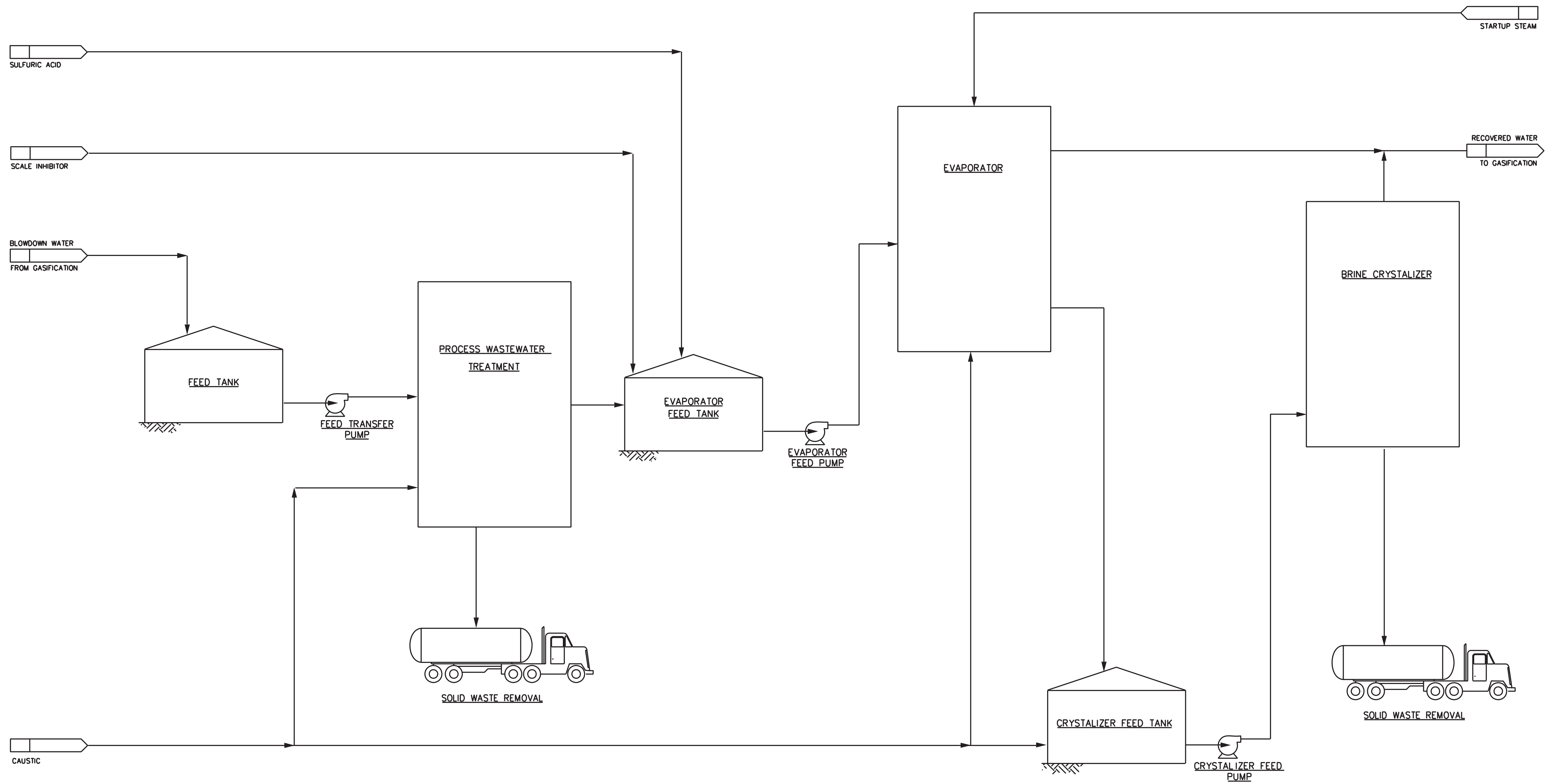
FIGURE 2-27



Source:
Fluor; Hydrogen Energy California, Kern County Power Project;
Flow Diagram, Process Wastewater Treatment/Zero Liquid Discharge;
Drawing No: A3RW-PDF-24-005A, Rev. 0 (03/23/09)

FLOW DIAGRAM
PROCESS WASTEWATER TREATMENT/
ZERO LIQUID DISCHARGE

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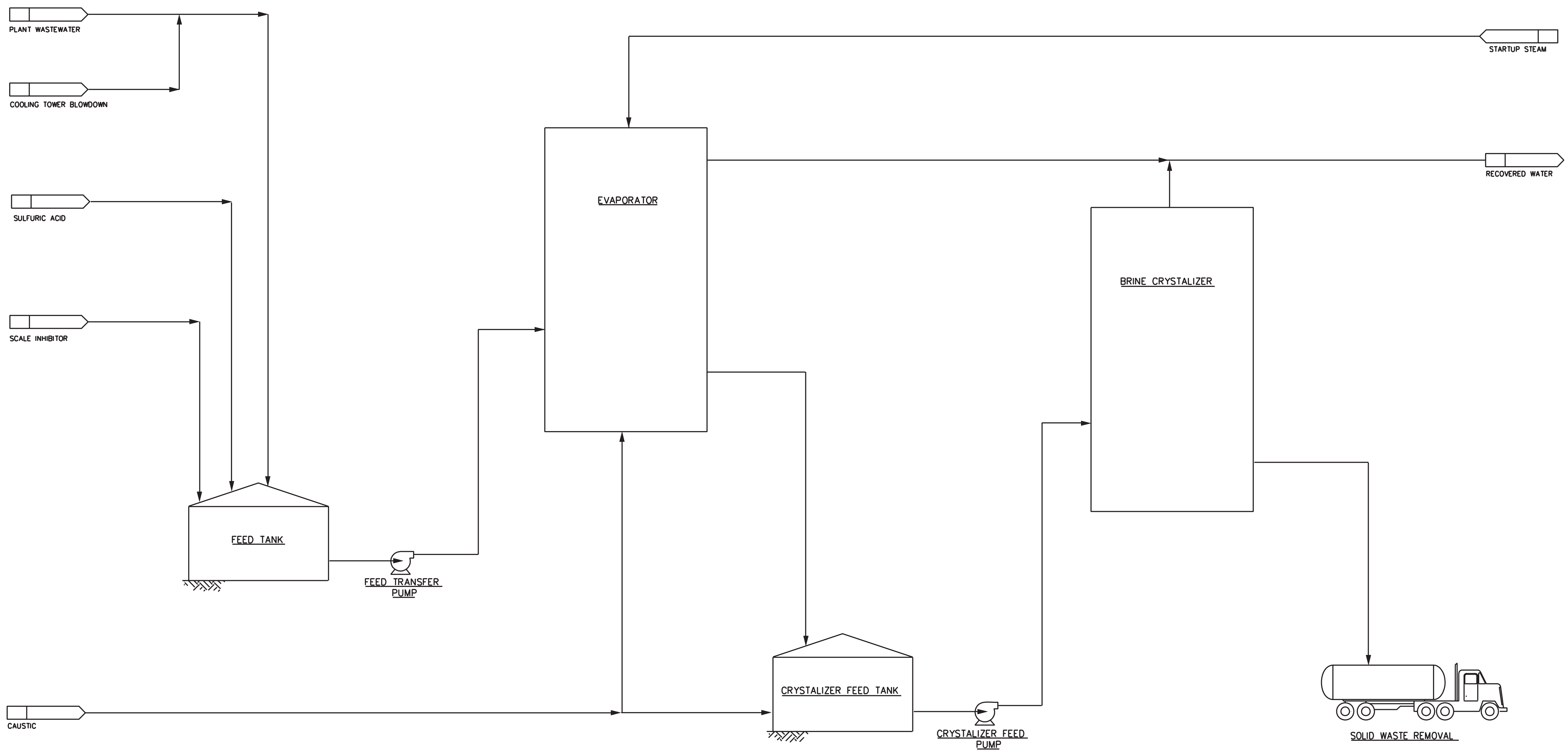
FIGURE 2-28

5/18/09 vsa..T:\HECA\GRAPHICS\2.0 Project Description\2-28_process wastewater zld.ai



Source:
Fluor; Hydrogen Energy California, Kern County Power Project;
Flow Diagram, Plant Wastewater Zero Liquid Discharge;
Drawing No: A3RW-PDF-25-008, Rev. 1 (03/23/09)

PLANT WASTEWATER
ZERO LIQUID DISCHARGE

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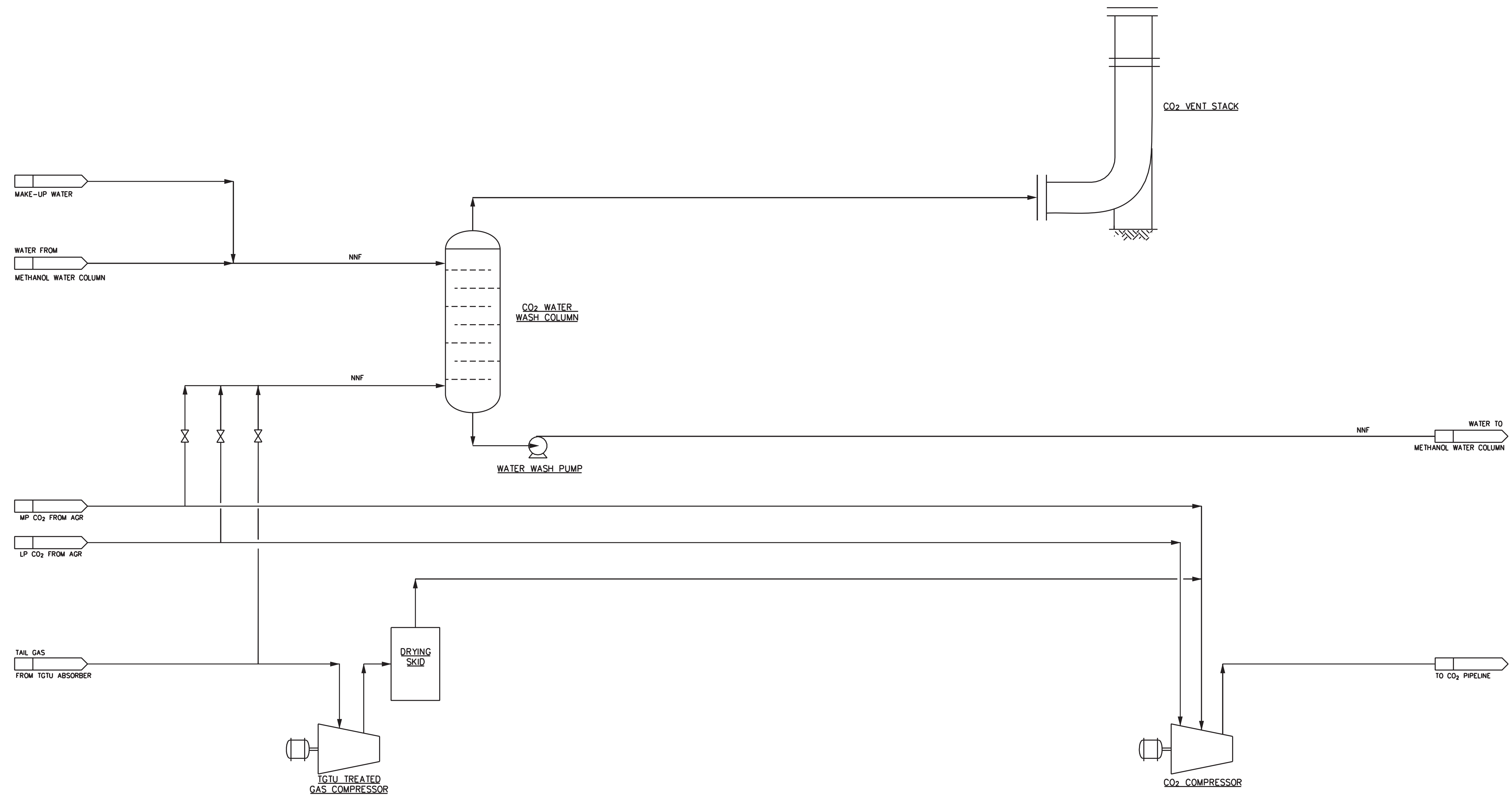
FIGURE 2-29



Source:
Fluor; Hydrogen Energy California, Kern County Power Project;
Flow Diagram, CO2 Compression & Venting Systems;
Drawing No: A3RW-PDF-25-011, Rev. 1 (03/06/09)

FLOW DIAGRAM
CARBON DIOXIDE COMPRESSION AND VENTING SYSTEMS

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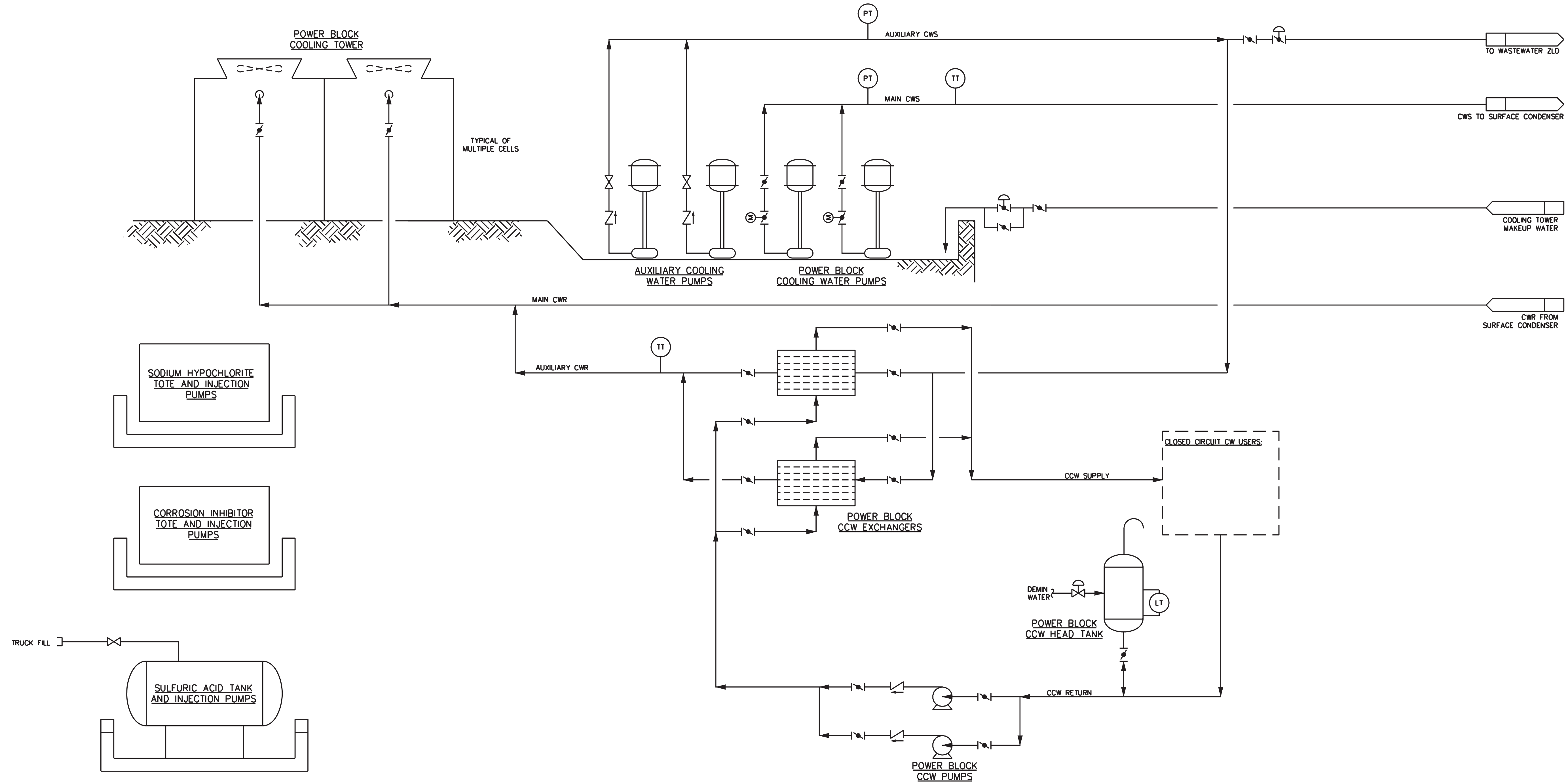
FIGURE 2-30



Source:
Fluor; Hydrogen Energy California, Kern County Power Project;
Flow Diagram, Cooling Water System;
Drawing No: A3RW-PDF-25-022, Rev. 1 (03/06/09)

FLOW DIAGRAM
COOLING WATER SYSTEM

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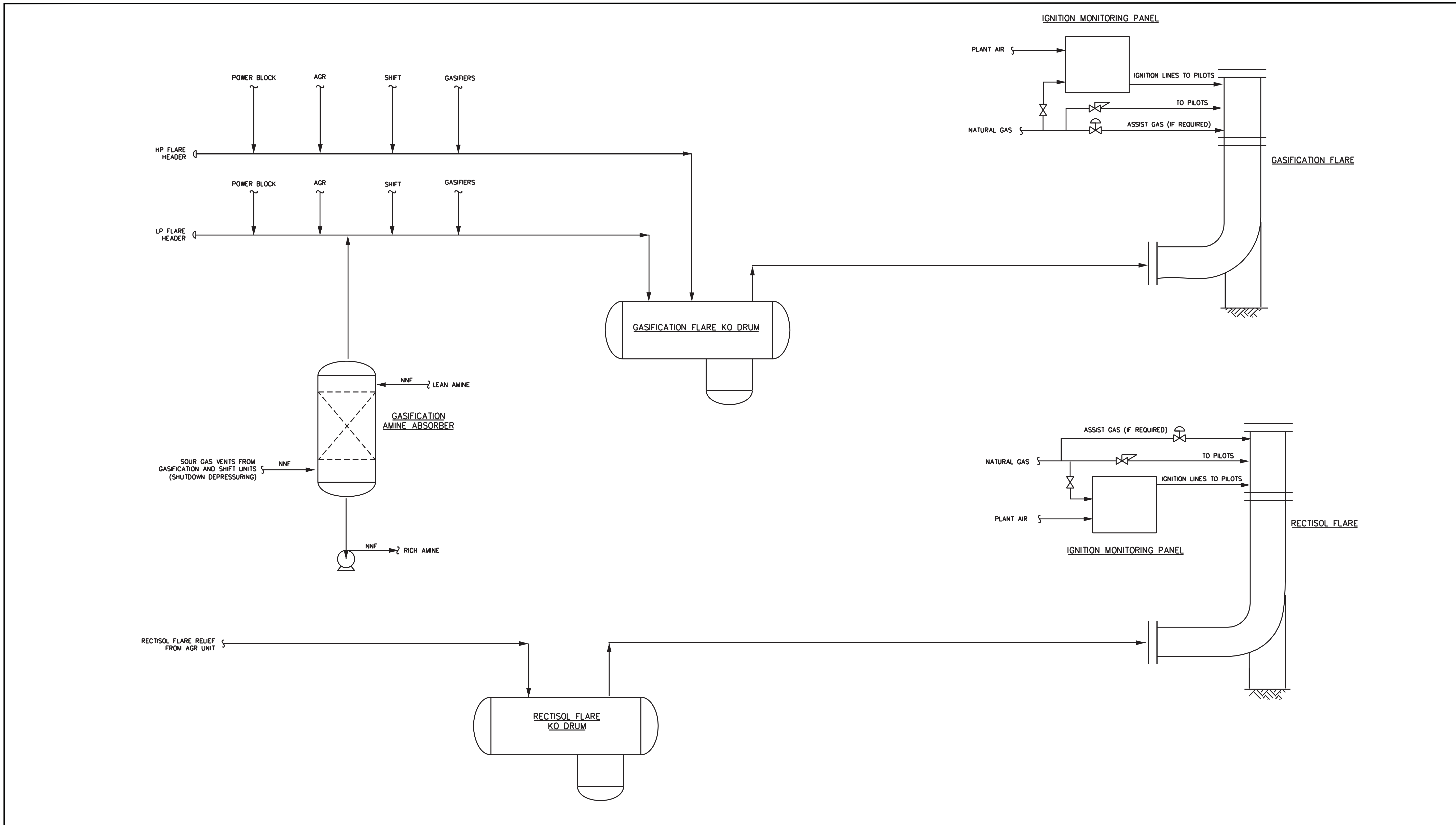
FIGURE 2-31

5/18/09 vsa..T:\HECA\GRAPHICS\2.0 Project Description\2-31_cooling water.ai



Source:
Fluor; Hydrogen Energy California, Kern County Power Project;
Flow Diagra, Gasification and Rectisol Flare Systems,
Drawing No: A3RW-PFD-25-025, Rev. 1 (03/23/09)

FLOW DIAGRAM
GASIFICATION AND RECTISOL
FLARE SYSTEMS

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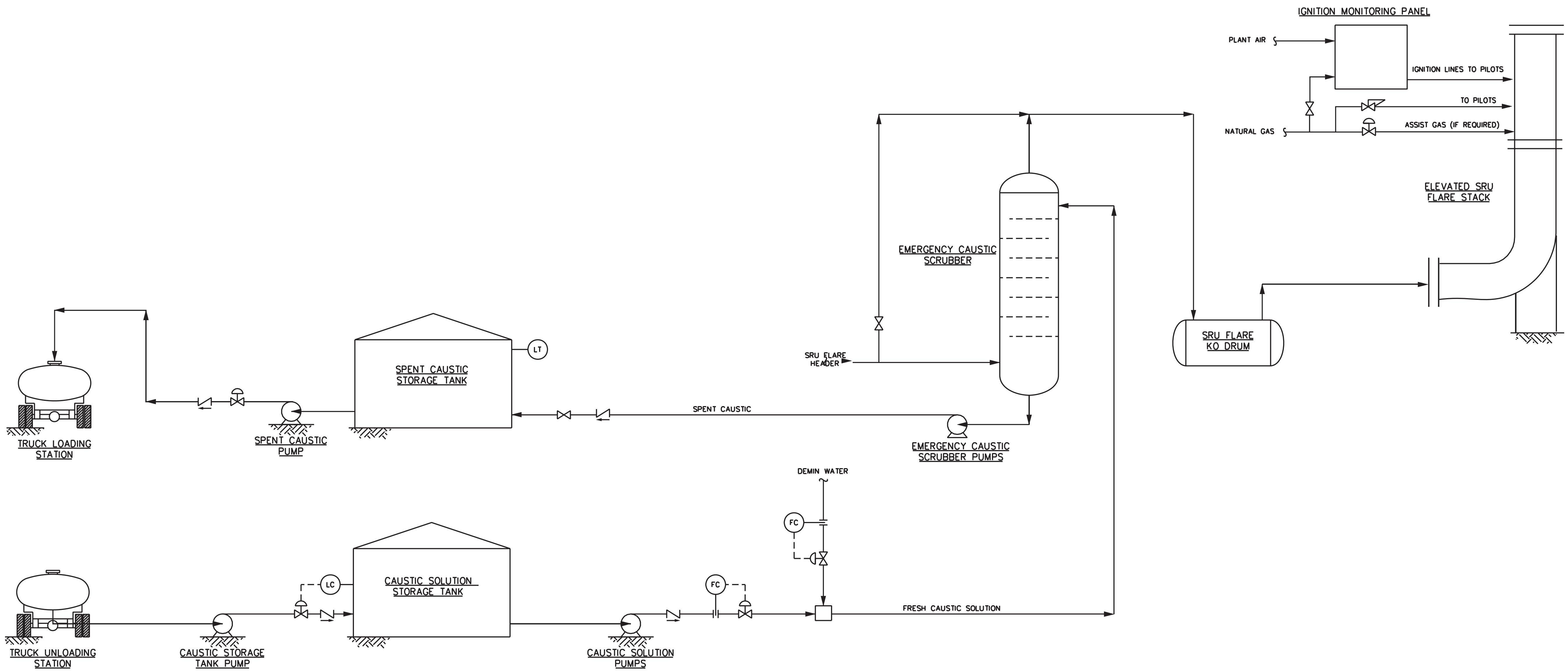
FIGURE 2-32



Source:
Fluor; Hydrogen Energy California, Kern County Power Project;
Flow Diagram, SRU Flare System;
Drawing No: A3RW-PDF-25-017, Rev. 2 (03/23/09)

FLOW DIAGRAM
SRU FLARE SYSTEM

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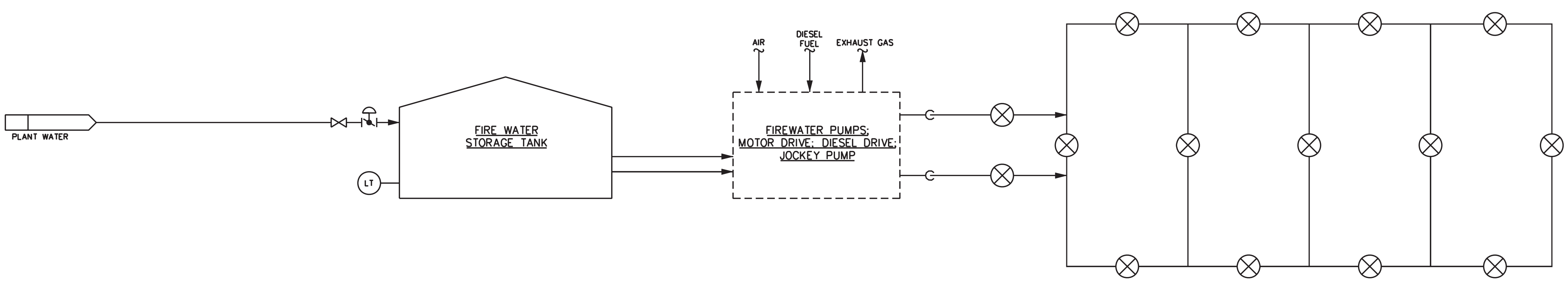
FIGURE 2-33

5/18/09 vsa..T:\HECA\GRAPHICS\2.0 Project Description\2-33_SRU flare.ai



FIRE WATER LOOP:

- ________ PIVs
- ________ HOSE STATIONS
- ________ MONITORS
- ________ ACTIVATED VALVES

FIREWATER VALVE HOUSES

- POWER BLOCK COOLING TOWER
- GASIFICATION COOLING TOWER
- STG LUBE OIL & BEARINGS
- CTG MAIN TRANSFORMER
- ASU COOLING TOWER

TYPICAL OF

BUILDING FIRE PROTECTION:

- CONTROL ROOM
- ADMIN
- MAINTENANCE

NOTES:

(1) ASSUME PREFABRICATED PUMPHOUSE CONTAINING

_ ELECTRIC FW PUMP
_ DIESEL FW PUMP
_ JOCKEY PUMP
_ CONTROLS & ALARMS
_ INTERNAL HEATING & LIGHTING

Source:
Fluor; Hydrogen Energy California, Kern County Power Project;
Flow Diagram, Fire Water System;
Drawing No: A3RW-PDF-25-018, Rev. 1 (03/23/09)

FLOW DIAGRAM
FIRE WATER SYSTEM

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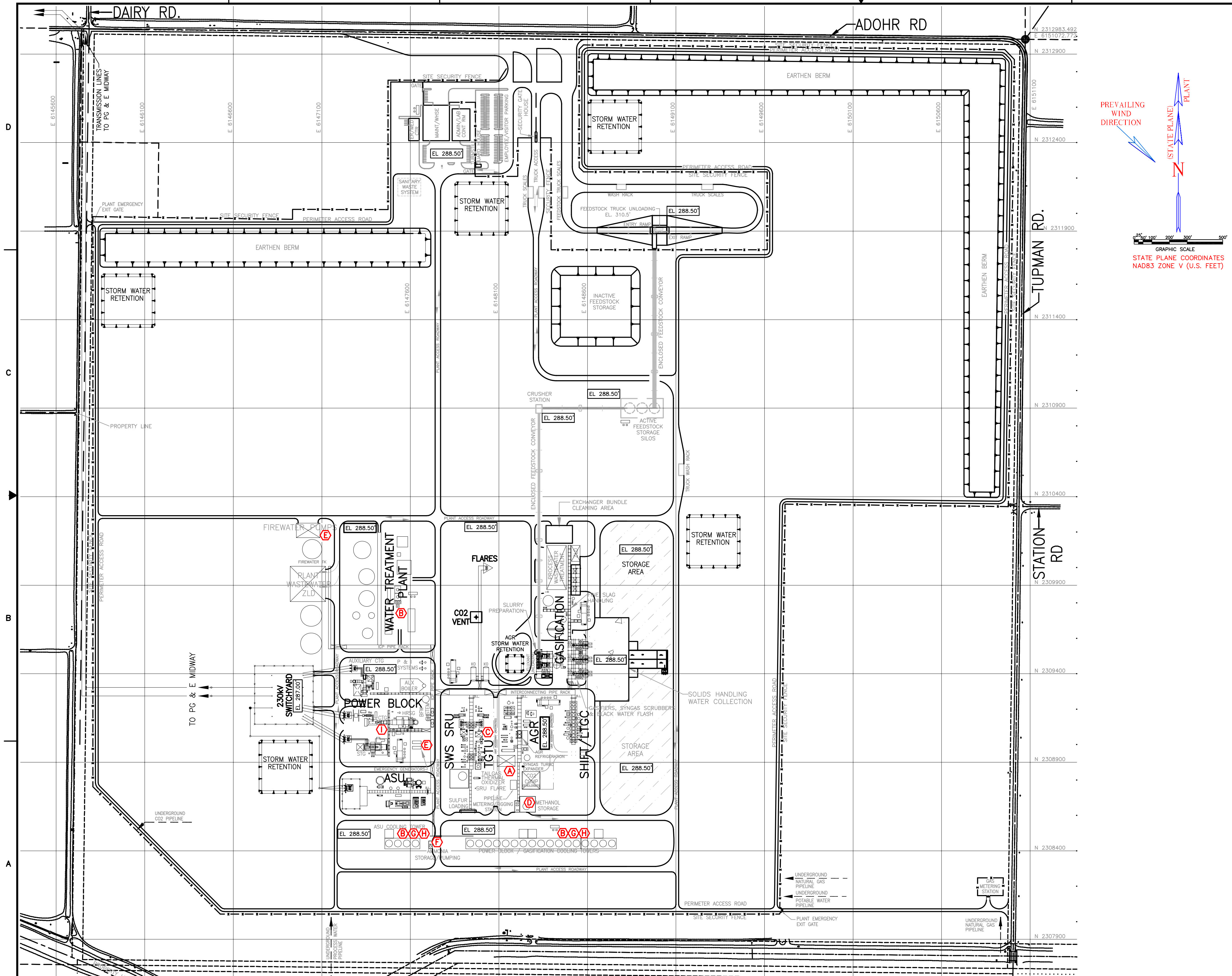
FIGURE 2-34



LEGEND

EL 288.50' = H.P. GRADE ELEVATION (FT.)

ASU = AIR SEPARATION UNIT
AGR = ACID GAS REMOVAL
SWS = SOUR WATER STRIPPING
SRU = SULFUR RECOVERY UNIT
TGTU = TAIL GAS TREATING UNIT
CTG = COMBUSTION TURBINE GENERATOR

HRSG = HEAT RECOVERY STEAM GENERATOR
STG = STEAM TURBINE GENERATOR
BFW = BOILER FEEDWATER SYSTEM
PDC = POWER DISTRIBUTION CENTER
LTGC = LOW TEMPERATURE GAS COOLING
ZLD = ZERO LIQUID DISCHARGE
P & I AIR = PLANT AND INSTRUMENT AIR

STORED HAZARDOUS MATERIALS**

ID	DESCRIPTION
A	SODIUM HYDROXIDE
B	WATER TREATMENT CHEMICALS
C	MOLTEN SULFUR
D	METHANOL
E	DIESEL FUEL
F	AQUEOUS AMMONIA
G	SULFURIC ACID
H	SODIUM HYPOCHLORITE
I	HYDROGEN

** AS DEFINED IN CCR, TITLE 22, SECTION 66261.22

Source:
Fluor; Hydrogen Energy California, Kern County Power Project;
Preliminary Hazardous Material Location Plan; Drawing No: SK-250-1003,
Rev. 0, 05/12/09

PRELIMINARY
HAZARDOUS MATERIAL LOCATION PLAN

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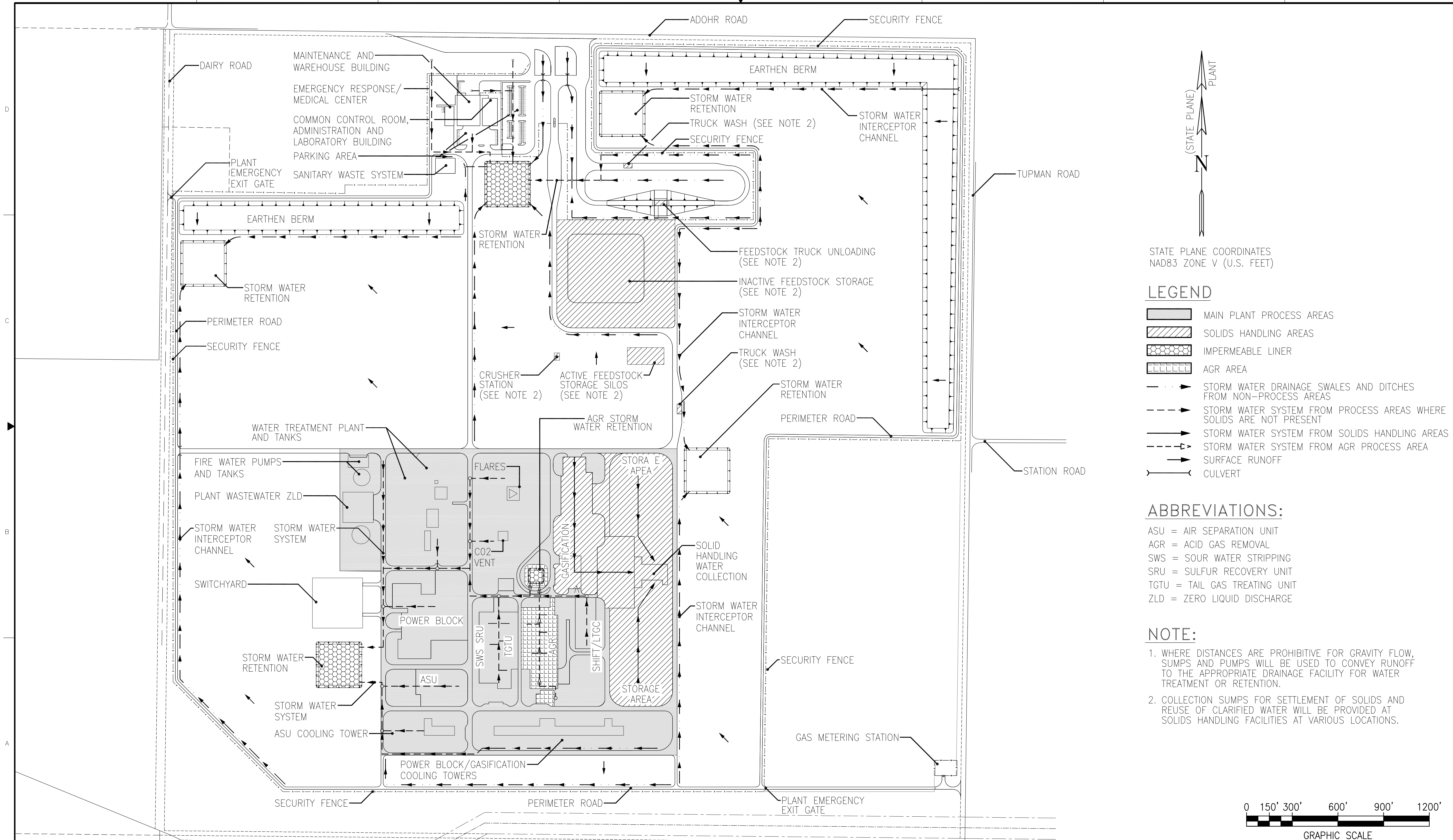
FIGURE 2-35

5/18/09 vsa..T:\HECA\GRAPHICS\2.0 Project Description\2-35_Prelim Haz Mat Loc Plan_051809.ai



Source:
Fluor; Hydrogen Energy California, Kern County Power Project;
Preliminary Drainage Plan; Drawing No: SK-210-1002, Rev. 0, 051209

PRELIMINARY STORM WATER DRAINAGE PLAN

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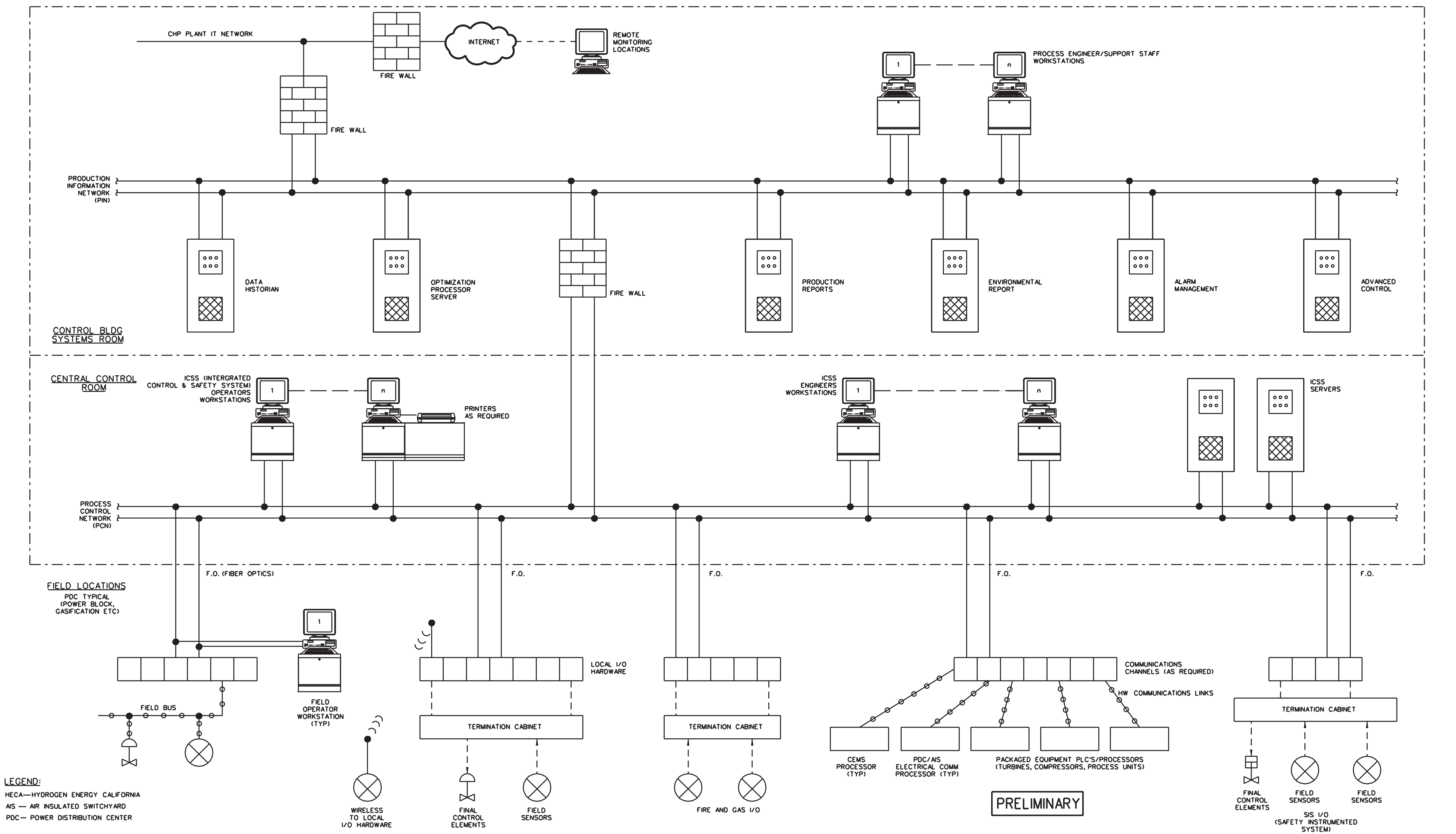
FIGURE 2-36

5/18/09 vsa..T:\HECA\GRAPHICS\2.0 Project Description\2-36_Prelim Drainage Plan_051809.ai



Source:
Fluor; Hydrogen Energy California, Kern County Power Project;
Control System Block Diagram;
Drawing No: A3RW-CC-70-001, Rev. 0 (06/04/08)

CONTROL SYSTEM BLOCK DIAGRAM

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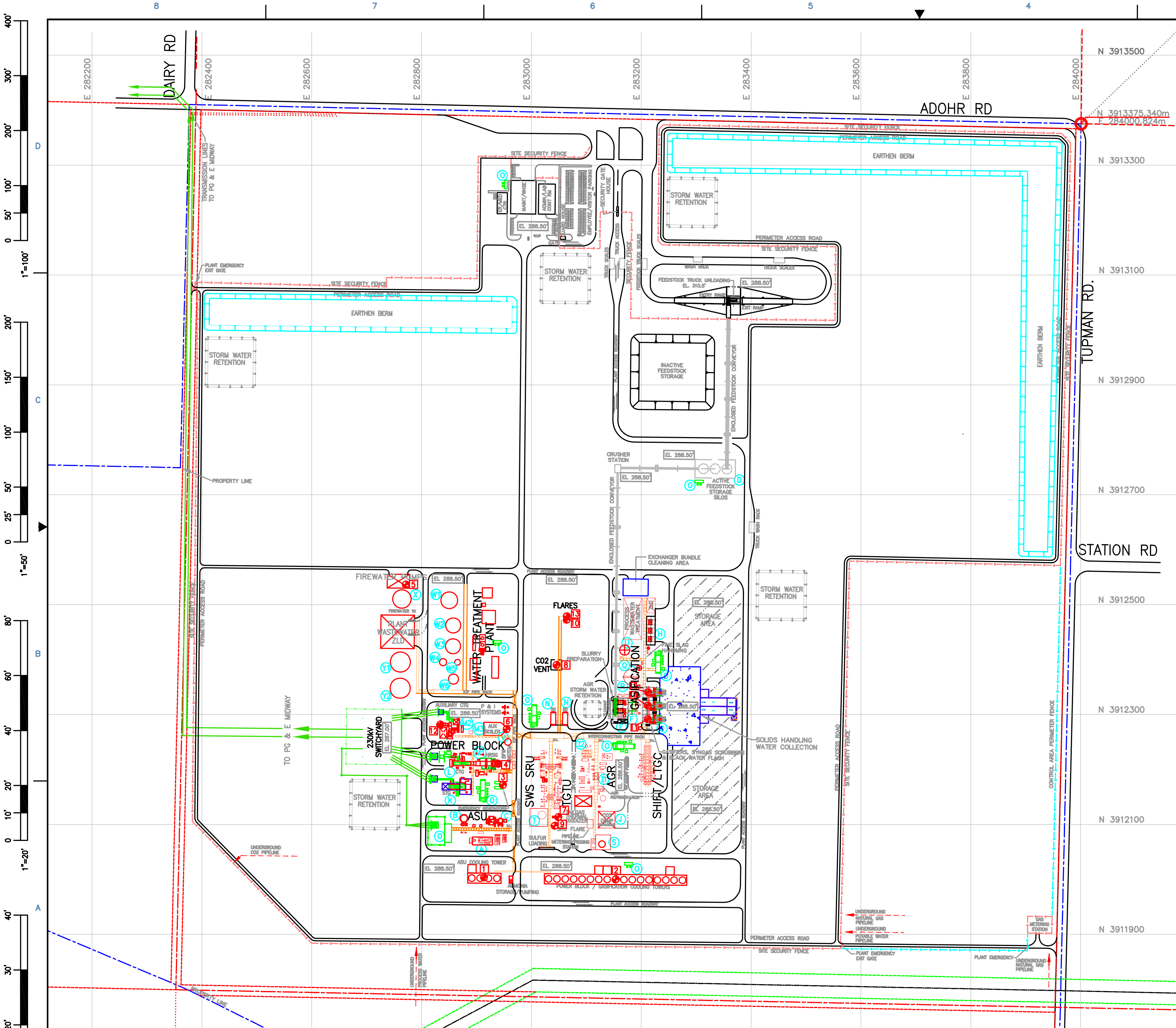
FIGURE 2-37



MAJOR STRUCTURES/EQUIPMENT AND TANKS

ID	DESCRIPTION	APPX. ELEVATIONS FROM GRADE (FT.)
A	ASU MAIN AIR COMPRESSOR ENCLOSURE	40
B	LIQUID OXYGEN STORAGE (LOX) TANK	90
C	AIR SEPARATION COLUMN CAN	205
D	FEEDSTOCK STORAGE SILOS	150
E	SLURRY PREPARATION BUILDING	165
F	SLURRY RUN TANKS (QTY 2)	75
G	GASIFICATION STRUCTURE	200
H	FINE SLAG HANDLING ENCLOSURE	70
I1	AGR REFRIGERATION COMPRESSOR ENCLOSURE	40
I2	AGR METHANOL WASH COLUMN	235
J	CO2 COMPRESSOR ENCLOSURE	50
K	STEAM TURBINE GENERATOR STRUCTURE	50
L	COMBUSTION TURBINE GENERATOR STRUCTURE	50
M1	HEAT RECOVERY STEAM GENERATOR STRUCTURE	90
M2	AUXILIARY CTG STRUCTURE	45
M3	AUXILIARY BOILER STRUCTURE	50
N	FLARE K.O. DRUMS (QTY 2)	35
O	POWER DISTRIBUTION CENTERS	25
Q	GREY WATER TANK	30'DIA X 40'H
R	SETTLER	85'DIA X 35'H
S	METHANOL STORAGE TANK	40'DIA X 40'H
T	SOUR WATER STRIPPER FEED TANK	48'DIA X 32'H
U	PROCESS WASTEWATER TREATMENT FEED TANK	60'DIA X 40'H
V	CONDENSATE STORAGE TANK	34'DIA X 24'H
W1	RAW WATER TANK	100'DIA X 48'H
W2	TREATED WATER TANK	90'DIA X 40'H
W3	PURIFIED WATER TANK	90'DIA X 48'H
W4	BACKWASH TANK	42.5'DIA X 48'H
W5	UTILITY WATER TANK	35'DIA X 32'H
W6	DEMINERALIZED WATER STORAGE TANK	60'DIA X 40'H
X	FIREWATER STORAGE TANK	110'DIA X 48'H
Y1	PLANT WASTEWATER ZLD FEED TANK–A	120'DIA X 48'H
Y2	PLANT WASTEWATER ZLD FEED TANK–B	120'DIA X 48'H

TANKS SET AT GRADE ELEVATION

EMISSIONS SOURCES (LEGEND):

ID	SOURCE	UTM COORDINATES (ROUNDED) EAST (METERS)	NORTH	APPX. ELEVATIONS FROM GRADE (FT.)
1	ASU COOLING TOWER	282914	3912003	55
2	POWERBLOCK & GASIFICATION COOLING TOWERS	283154	3912000	55
3	EMERGENCY GENERATORS	282948	3912172	20
4	HRSG STACK	282940	3912210	213
5	FIRE WATER PUMP DIESEL ENGINE	282771	3912537	20
6	AUXILIARY BOILER	282955	3912273	80
7	TAIL GAS THERMAL OXIDIZER	283049	3912113	165
8	CO2 VENT	283046	3912390	260
9	SRU FLARE	283042	3912098	250
10	GASIFICATION FLARE	283064	3912473	250
11a	GASIFIER WARMING VENT	283212	3912340	210
11b	GASIFIER WARMING VENT	283212	3912316	210
11c	GASIFIER WARMING VENT	283212	3912292	210
12	AUXILIARY CTG STACK	282834	3912282	110
13	RECTISOL FLARE	283064	3912474	250

LEGEND

EL 288.50' = H.P. GRADE ELEVATION (FT.)
ASU = AIR SEPARATION UNIT
AGR = ACID GAS REMOVAL
SWS = SOUR WATER STRIPPING
SRU = SULFUR RECOVERY UNIT
TGTU = TAIL GAS TREATING UNIT
CTG = COMBUSTION TURBINE GENERATOR
HRSG = HEAT RECOVERY STEAM GENERATOR
STG = STEAM TURBINE GENERATOR
BFW = BOILER FEEDWATER SYSTEM
PDC = POWER DISTRIBUTION CENTER
LTGC = LOW TEMPERATURE GAS COOLING
ZLD = ZERO LIQUID DISCHARGE
P & I AIR = PLANT AND INSTRUMENT AIR

Source:
Fluor; Hydrogen Energy California, Kern County Power Project;
Preliminary Plot Plan; Drawing No: SK-250-1002, Rev. 0, 05/12/09

PRELIMINARY
EMISSIONS SOURCES PLOT PLAN

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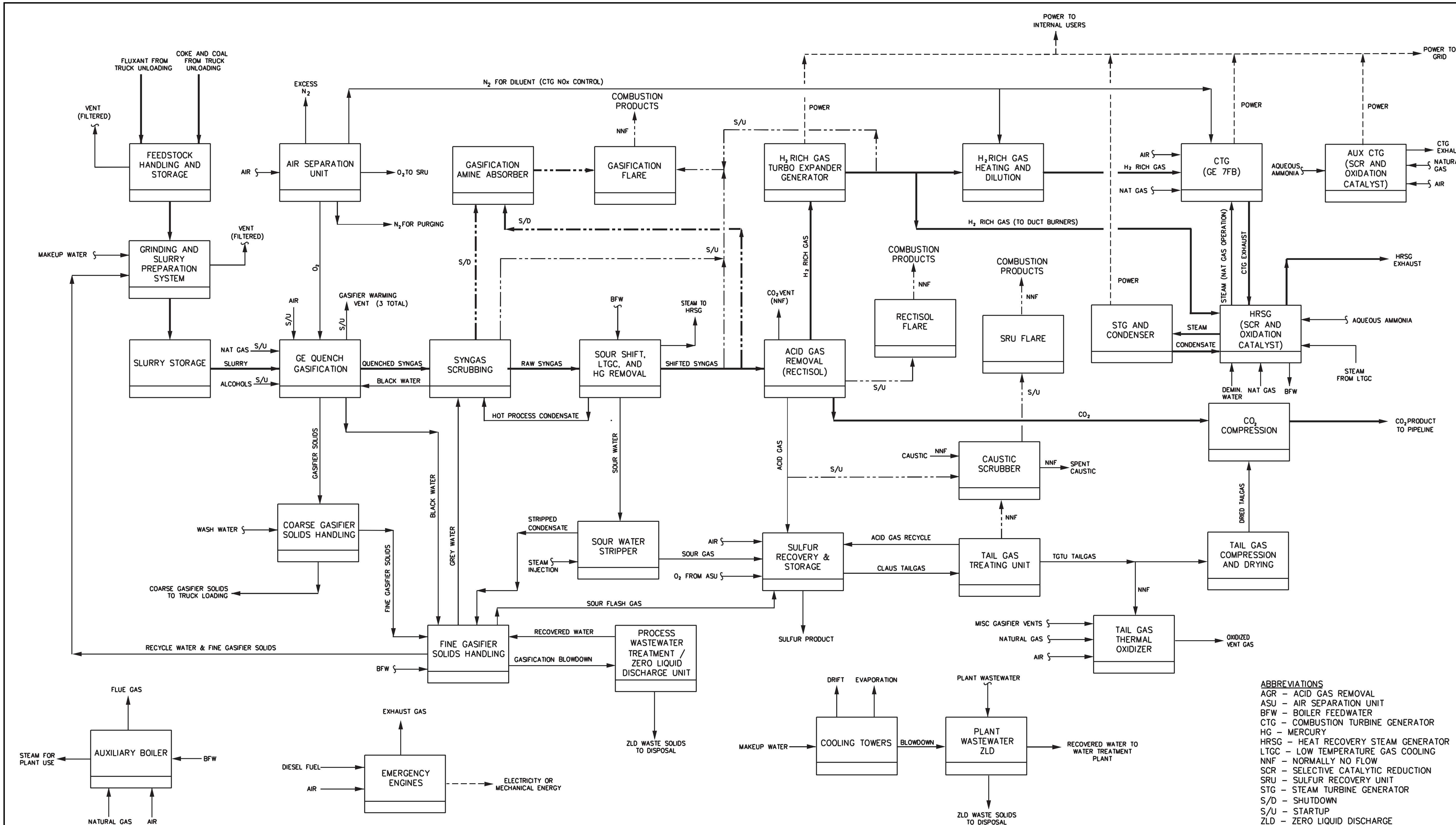
FIGURE 2-38

5/18/09 vsa..T:\HECA\GRAPHICS\2.0 Project Description\2-38_Prelim Emissions_051809.ai



Source:
Fluor; Hydrogen Energy California, Kern County Power Project;
Block Flow Diagram with Air Emission Sources;
Drawing No: A3RW-BFD-25-023, Rev. 2 (04/13/09)

BLOCK FLOW DIAGRAM WITH AIR EMISSION SOURCES

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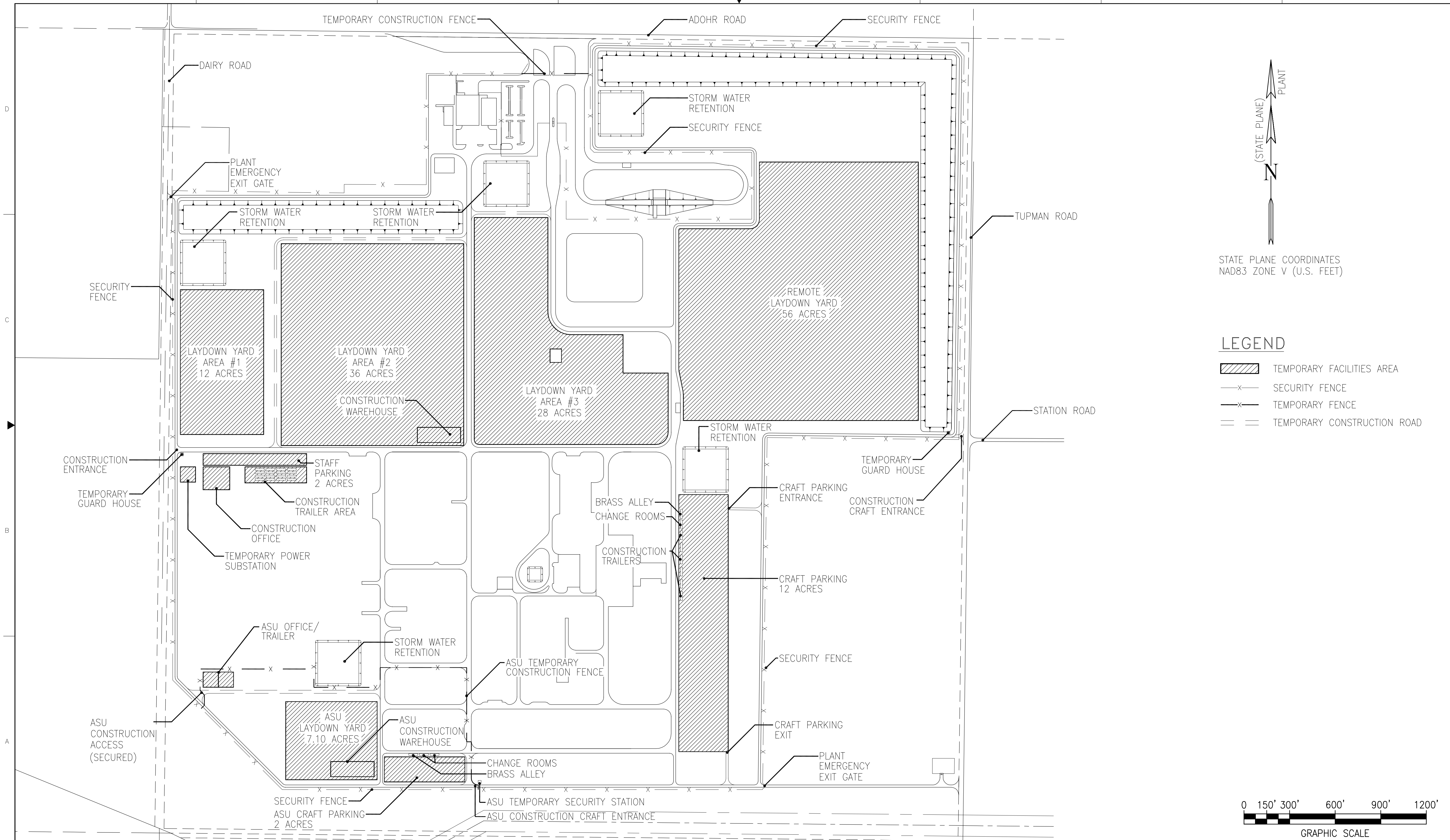
FIGURE 2-39



Source:
Fluor; Hydrogen Energy California, Kern County Power Project;
Preliminary Construction Facilities Plan; Drawing No: SK-500-1001, Rev. 0 05/12/09

PRELIMINARY TEMPORARY CONSTRUCTION FACILITIES PLAN

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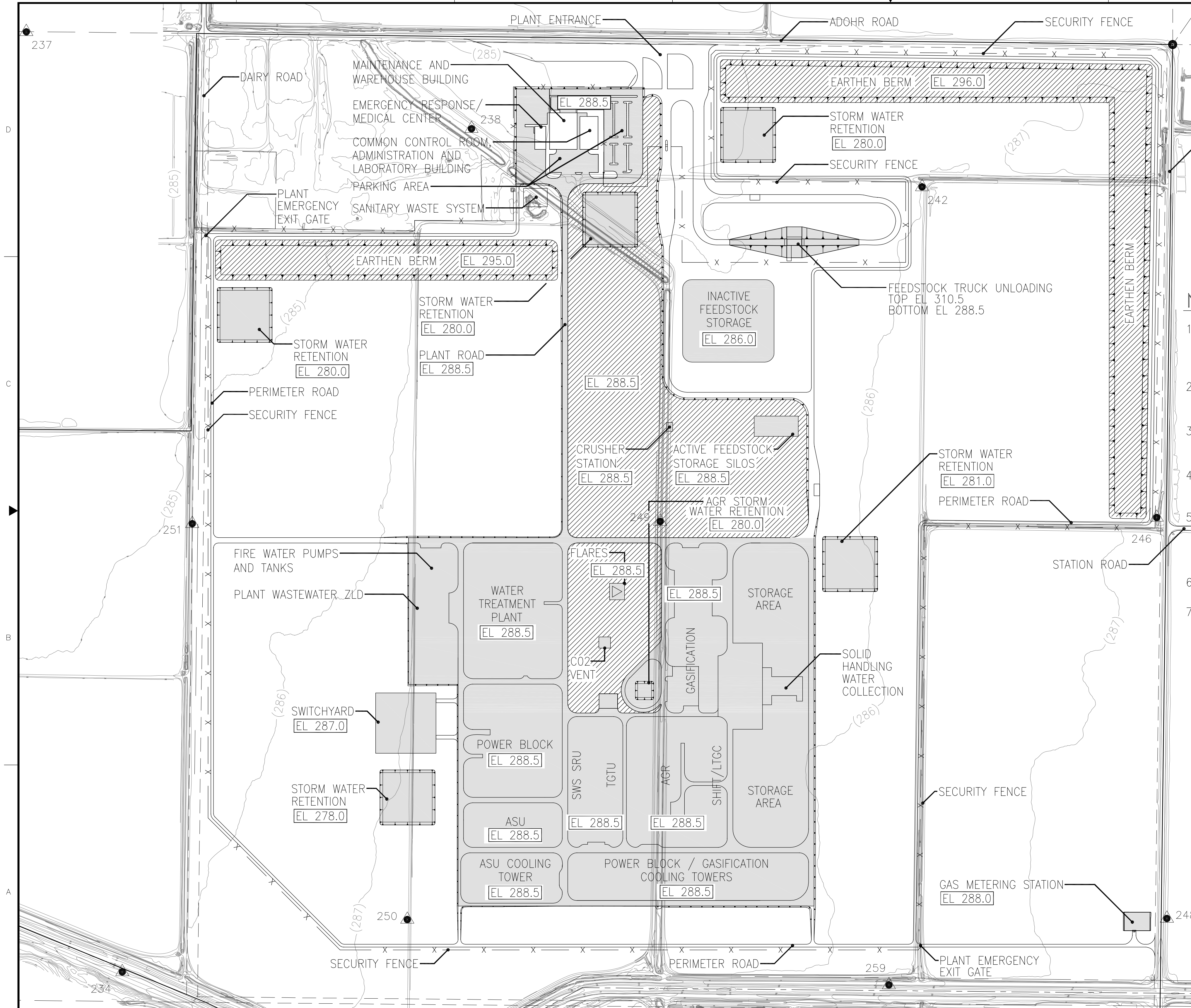
FIGURE 2-40

5/18/09 vsa/..T:\HECA\GRAPHICS\2.0 Project Description\2-40_PrelimTemp Const Fac Plan_051809.ai



NOTE:

1. EARTHWORK QUANTITIES ARE APPROXIMATE AND ARE BASED ON THE PRELIMINARY GEOTECHNICAL INVESTIGATION RECOMMENDATIONS PERTAINING TO THE REMOVAL OF UNSUITABLE SOILS.
2. UNSUITABLE SOIL MATERIAL WILL BE EXCAVATED, AND USED TO CONSTRUCT THE EARTHEN BERMS AND TO LEVEL THE OPEN AREAS AS SHOWN ON THE PLAN.
3. IMPORT MATERIAL WILL BE USED TO FILL THE VOID REMAINING FROM THE REMOVAL OF UNSUITABLE MATERIAL AND TO RAISE GRADE TO THE ELEVATIONS INDICATED.
4. PRELIMINARY EARTHWORK QUANTITIES AND FINAL GRADES MAY VARY DEPENDING ON FINAL GEOTECHNICAL RECOMMENDATIONS AND PLOT PLAN.
5. COORDINATE LOCATIONS SHOWN ARE BASED ON THE CALIFORNIA COORDINATE SYSTEM (CCS 83), ZONE V, 2007.0 EPOCH, RELATIVE TO THE NORTH AMERICAN DATUM OF 1983 (NAD 83). ELEVATIONS ARE BASED ON THE NORTH AMERICAN VERTICAL DATUM OF 1988 (NAVD88).
6. PIPING, EQUIPMENT AND FOUNDATIONS NOT SHOWN IN PROCESS AREAS FOR CLARITY.
7. GRADING SYMBOLOGY SHOWN DEPICTS PROPOSED ELEVATIONS FOR DELINEATED AREA.

LEGEND:

EL 288.5 H.P. GRADE ELEVATION
TOP / BOTTOM DENOTES SLOPE
PAD AREA
EXCAVATED FILL MATERIAL
SURVEY MONUMENT POINT (SEE NOTE 2)

ABBREVIATIONS:

ASU = AIR SEPARATION UNIT
AGR = ACID GAS REMOVAL
LTGC = LOW TEMPERATURE GAS COOLING
SWS = SOUR WATER STRIPPING
SRU = SULFUR RECOVERY UNIT
TGTU = TAIL GAS TREATING UNIT
ZLD = ZERO LIQUID DISCHARGE

SURVEY MONUMENT DATA			
CALIFORNIA STATE PLANE COORDINATES			
POINT NO.	NORTHING	EASTING	ELEVATION
234	2,307,921.77	6,145,338.58	291.05
237	2,313,052.82	6,144,814.75	286.23
238	2,312,523.86	6,147,244.89	286.72
242	2,312,206.46	6,149,704.56	286.79
246	2,310,401.98	6,150,985.50	288.23
248	2,308,213.18	6,151,041.09	287.33
249	2,310,380.25	6,148,274.74	287.69
250	2,308,207.70	6,146,894.35	287.45
251	2,310,368.06	6,145,720.47	286.12
259	2,307,850.54	6,149,523.60	292.75

EARTHWORK VOLUME	
EXCAVATION *	IMPORT *
700,000	1,100,000 CY
* SEE NOTES	

Source:
Fluor; Hydrogen Energy California, Kern County Power Project;
Preliminary Grading Plan; Drawing No: SK-210-1001, Rev. 0, 05/12/09

PRELIMINARY GRADING PLAN

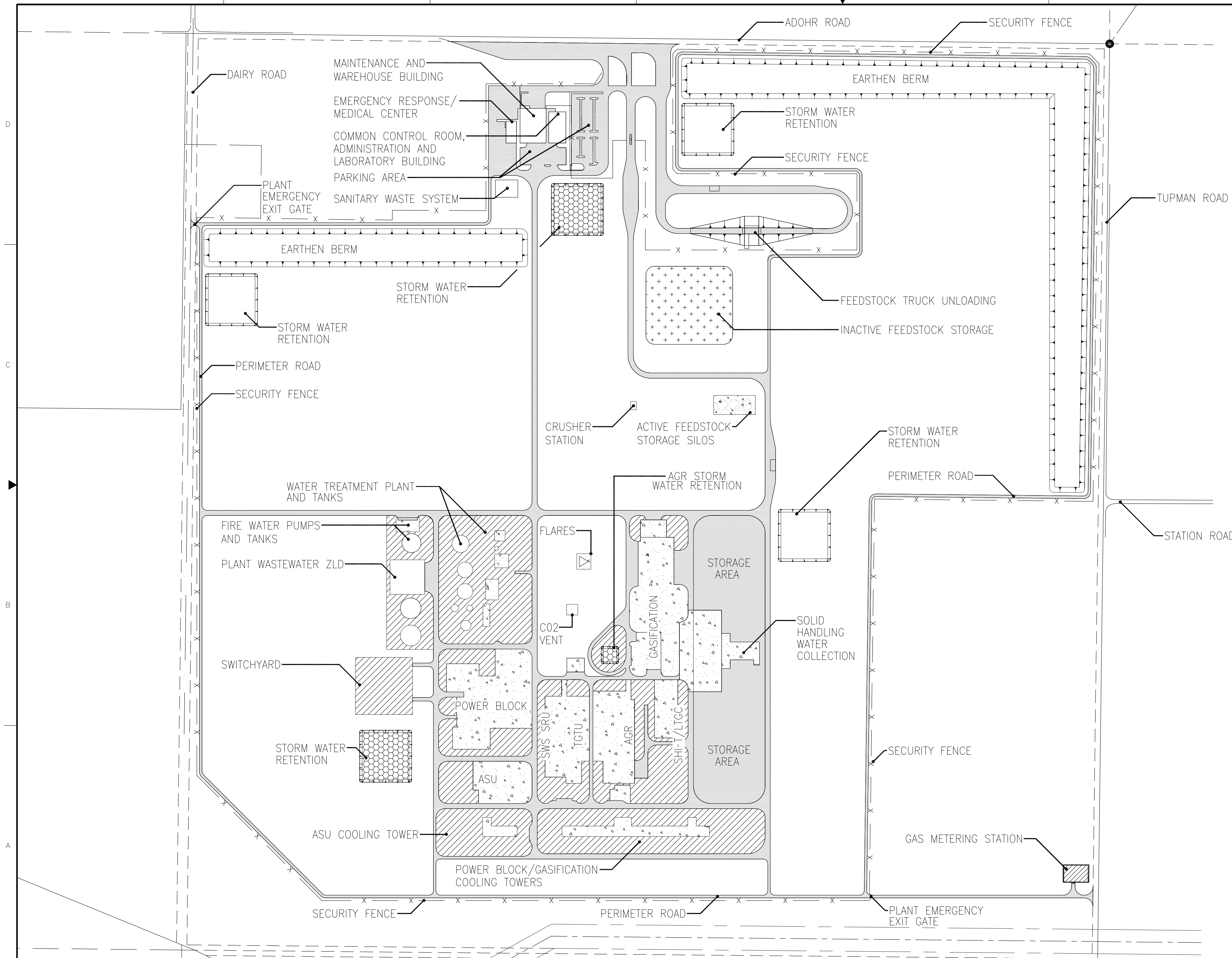
May 2009
28067571

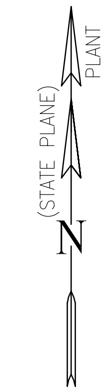
Hydrogen Energy California (HECA)
Kern County, California

URS

FIGURE 2-41

5/18/09 vsa.T:\HECA\GRAPHICS\2.0 Project Description\2-41_Prelim Grading Plan_051809.ai





STATE PLANE COORDINATES
NAD83 ZONE V (U.S. FEET)

LEGEND

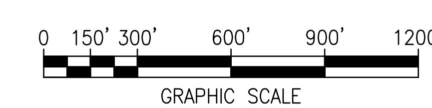
- ASPHALT CONCRETE PAVEMENT
- CONCRETE PAVEMENT
- CRUSHED ROCK SURFACING
- CLAY LINER (12" CLAY)
- IMPERMEABLE LINER

ABBREVIATIONS:

ASU = AIR SEPARATION UNIT
AGR = ACID GAS REMOVAL
LTGC = LOW TEMPERATURE GAS COOLING
SWS = SOUR WATER STRIPPING
SRU = SULFUR RECOVERY UNIT
TGTU = TAIL GAS TREATING UNIT
ZLD = ZERO LIQUID DISCHARGE

NOTE:

1. PAVING SYMBOLOGY SHOWN DEPICTS PROPOSED SURFACE TREATMENT FOR DELINEATED AREA.
2. PAVED DRIVEWAYS, WALKWAYS AND CRANE ACCESS LOCATIONS WILL BE PROVIDED TO SUPPORT PLANT OPERATIONS AND MAINTENANCE. THESE FEATURES WILL BE IDENTIFIED AND SIZED DURING SUBSEQUENT DESIGN AND WILL BE DETAILED ON THE APPROPRIATE CIVIL/STRUCTURAL ENGINEERING DRAWINGS.



Source:
Fluor; Hydrogen Energy California, Kern County Power Project;
Preliminary Paving Plan; Drawing No: SK-210-1003, Rev. 0, 05/14/09

PRELIMINARY PAVING PLAN

May 2009
28067571

Hydrogen Energy California (HECA)
Kern County, California

URS

FIGURE 2-42

5/18/09 vsa..T:\HECA\GRAPHICS\2.0 Project Description\2-42_Prelim Paving Plan_051809.ai

Adequacy Issue: Adequate ____ Inadequate ____ **DATA ADEQUACY WORKSHEET** Revision No. 0 Date ____

Technical Area: **Efficiency** Project: ____ Technical Staff: ____

Project Manager: ____ Docket: ____ Technical Senior: ____

Siting Regulations	Information	AFC Page Number and Section Number	Adequate Yes or No	Information Required To Make AFC Conform With Regulations
Appendix B (g) (1)	...provide a discussion of the existing site conditions, the expected direct, indirect and cumulative impacts due to the construction, operation and maintenance of the project, the measures proposed to mitigate adverse environmental impacts of the project, the effectiveness of the proposed measures, and any monitoring plans proposed to verify the effectiveness of the mitigation.	Entire AFC		
Appendix B (h) (4) (A)	Heat and mass balance diagrams for design conditions for each mode of operation.	Table 2-11, p. 2-22, Table 2-12, p. 2-23 Figure 2-3.		
Appendix B (h) (4) (B)	Annual fuel consumption in BTUs for each mode of operation, including hot restarts and cold starts.	Table 2-11, p. 2-22		
Appendix B (h) (4) (C)	Annual net electrical energy produced in MWh for each mode of operation including starts and shutdowns.	Table 2-11, p. 2-22, Table 2-12, p. 2-23 Page 2-1, Table 2-11, p. 2-22, Section 2.5.2, p. 2-64, 2.5.3, p. 2-69		
Appendix B (h) (4) (D)	Number of hours the plant will be operated in each design condition in each year.	Section 2.5, p. 2-64		
Appendix B (h) (4) (E)	If the project will be a cogeneration facility, calculations showing compliance with applicable efficiency and operating standards.	N/A		
Appendix B (h) (4) (F)	A discussion of alternative generating technologies available for the project, including the projected efficiency of each, and an explanation why the chosen equipment was selected over these alternatives.	Section 6-4		

Adequacy Issue:	Adequate ____	Inadequate ____	DATA ADEQUACY WORKSHEET	Revision No. 0	Date ____
Technical Area:	**Efficiency**		Project: ____	Technical Staff: ____	
Project Manager:	____		Docket: ____	Technical Senior: ____	

SITING REGULATIONS	INFORMATION	AFC PAGE NUMBER AND SECTION NUMBER	ADEQUATE YES OR NO	INFORMATION REQUIRED TO MAKE AFC CONFORM WITH REGULATIONS
Appendix B (i) (1) (A)	Tables which identify laws, regulations, ordinances, standards, adopted local, regional, state, and federal land use plans, leases, and permits applicable to the proposed project, and a discussion of the applicability of, and conformance with each. The table or matrix shall explicitly reference pages in the application wherein conformance, with each law or standard during both construction and operation of the facility is discussed; and	Sections 5.1 – 5.16, Section 4, Section 7, Appendix B		
Appendix B (i) (1) (B)	Tables which identify each agency with jurisdiction to issue applicable permits, leases, and approvals or to enforce identified laws, regulations, standards, and adopted local, regional, state and federal land use plans, and agencies which would have permit approval or enforcement authority, but for the exclusive authority of the commission to certify sites and related facilities.	Sections 5.1 – 5.16, Section 4, Section 7		
Appendix B (i) (2)	The name, title, phone number, address (required), and email address (if known), of an official who was contacted within each agency, and also provide the name of the official who will serve as a contact person for Commission staff.	Sections 5.1 – 5.16, Section 4, Section 7		
Appendix B (i) (3)	A schedule indicating when permits outside the authority of the commission will be obtained and the steps the applicant has taken or plans to take to obtain such permits.	Sections 5.1 – 5.16		

Adequacy Issue: Adequate ____ Inadequate ____ DATA ADEQUACY WORKSHEET Revision No. 0 Date ____

Technical Area: **Facility Design** Project: ____ Technical Staff: ____

Project Manager: ____ Docket: ____ Technical Senior: ____

Siting Regulations	**Information**	**AFC Page Number and Section Number**	**Adequate Yes or No**	**Information Required To Make AFC Conform With Regulations**
Appendix B (h) (1) (A)	A description of the site conditions and investigations or studies conducted to determine the site conditions used as the basis for developing design criteria. The descriptions shall include, but not be limited to, seismic and other geologic hazards, adverse conditions that could affect the project's foundation, adverse meteorological and climatic conditions, and flooding hazards, if applicable.	Entire AFC		
Appendix B (h) (1) (B)	A discussion of any measures proposed to improve adverse site conditions.	Entire AFC		
Appendix B (h) (1) (C)	A description of the proposed foundation types, design criteria (including derivation), analytical techniques, assumptions, loading conditions, and loading combinations to be used in the design of facility structures and major mechanical and electrical equipment	Appendix B1 (subsection 3.1.2)		
Appendix B (h) (1) (D)	For each of the following facilities and/or systems, provide a description including drawings, dimensions, surface-area requirements, typical operating data, and performance and design criteria for protection from impacts due to adverse site conditions:			
Appendix B (h) (1) (D) (i)	The power generation system;	Section 2.3, Pages 2-31 – 2-38 Figures 2-18 – 2-22		
Appendix B (h) (1) (D) (ii)	The heat dissipation system;	Section 2.4.7, Pages 2-44 – 2-46 Figure 2-31		

Adequacy Issue:	Adequate ____	Inadequate ____	DATA ADEQUACY WORKSHEET	Revision No. 0	Date ____
Technical Area:	**Facility Design**	Project:		Technical Staff:	
Project Manager:		Docket:		Technical Senior:	

SITING REGULATIONS	**INFORMATION**	**AFC PAGE NUMBER AND SECTION NUMBER**	**ADEQUATE YES OR NO**	**INFORMATION REQUIRED TO MAKE AFC CONFORM WITH REGULATIONS**
Appendix B (h) (1) (D) (iii)	The cooling water supply system, and, where applicable, pre-plant treatment procedures;	Section 2.1.6, p. 2-6, Sections 2.4.5, p. 2-43 Figures 2-10, 2-29, 2-31		
Appendix B (h) (1) (D) (iv)	The atmospheric emission control system;	Section 2-1, p. 2-1, Section 2.2.5, p. 2-29, Section 2.3.1, p. 2-31, Section 2.3.2.3, p2-24, Section 2.4.13, p. 2-51, 2-, Section 2.4.17, p. 2-63 Table 2-21 Figure 2-38		
Appendix B (h) (1) (D) (v)	The waste disposal system and on-site disposal sites;	Section 2.1.9.5, p. 2-19, Sections 2.4.4 - 2.4.5, p. 2-42 – 2-43, Section 2.4.15, p. 2-56, Tables 2-19 and 2-20		
Appendix B (h) (1) (D) (vi)	The noise emission abatement system;	Section 5.5, Appendix K		
Appendix B (h) (1) (D) (vii)	The geothermal resource conveyance and re-injection lines (if applicable);	N/A		
Appendix B (h) (1) (D) (viii)	Switchyards/transformer systems; and	Section 2.1.9.1, p. 2-17, Section 2.3.1, p. 2-31, Section 2.3.4, p. 2-37, Section 2.6.1.10, p. 2-77, Table 2-8 Figures 2-11, 2-19, 2-20, 2-21 2-22 Section 4, Appendix B		
Appendix B (h) (1) (D) (ix)	Other significant facilities, structures, or system components proposed by the applicant.	Section 2.2, p. 2-21, Section 2.3, p. 2-31, Section 2.4, p. 2-38		

Adequacy Issue: Adequate ____ Inadequate ____ DATA ADEQUACY WORKSHEET Revision No. 0 Date ____

Technical Area: **Reliability** Project: ____ Technical Staff: ____

Project Manager: ____ Docket: ____ Technical Senior: ____

SITING REGULATIONS	INFORMATION	AFC PAGE NUMBER AND SECTION NUMBER	ADEQUATE YES OR NO	INFORMATION REQUIRED TO MAKE AFC CONFORM WITH REGULATIONS
Appendix B (g) (1)	...provide a discussion of the existing site conditions, the expected direct, indirect and cumulative impacts due to the construction, operation and maintenance of the project, the measures proposed to mitigate adverse environmental impacts of the project, the effectiveness of the proposed measures, and any monitoring plans proposed to verify the effectiveness of the mitigation.	Section 2		
Appendix B (h) (3) (A)	A discussion of the sources and availability of the fuel or fuels to be used over the estimated service life of the facilities.	Section 2.1.8, p. 2-9		
Appendix B (h) (3) (B)	A discussion of the anticipated service life and degree of reliability expected to be achieved by the proposed facilities based on a consideration of:	Section 2.8, p. 2-94		
Appendix B (h) (3) (B) (i)	Expected overall availability factor, and annual and lifetime capacity factors;	Section 2.8, p. 2-89, Table 2-12, Table 2-27		
Appendix B (h) (3) (B) (ii)	The demonstrated or anticipated feasibility of the technologies, systems, components, and measures proposed to be employed in the facilities, including the power generation system, the heat dissipation system, the water supply system, the reinjection system, the atmospheric emission control system, resource conveyance lines, and the waste disposal system;	Section 2.8, p. 2-94, Section 2.2, p. 2-21, Section 6		
Appendix B (h) (3) (B) (iii)	Geologic and flood hazards, meteorologic conditions and climatic extremes, and cooling water availability;	Section 2.7.1, p. 2-89, Table 2-2, p. 2-8, Section 2.1.8.4, p. 2-16, Appendix O3.		

Adequacy Issue: Adequate ____ Inadequate ____ DATA ADEQUACY WORKSHEET Revision No. 0 Date ____

Technical Area: **Reliability** Project: ____ Technical Staff: ____

Project Manager: ____ Docket: ____ Technical Senior: ____

SITING REGULATIONS	INFORMATION	AFC PAGE NUMBER AND SECTION NUMBER	ADEQUATE YES OR NO	INFORMATION REQUIRED TO MAKE AFC CONFORM WITH REGULATIONS
Appendix B (h) (3) (B) (iv)	Special design features adopted by the applicant or resource supplier to ensure power plant reliability including equipment redundancy; and	Section 2.3.4, p. 2-37, Section 2.5.1, p. 2-64, Section 2.7.2.3, p. 2-91		
Appendix B (h) (3) (B) (v)	For technologies not previously installed and operated in California, the expected power plant maturation period.	Section 2.8, p. 2-94		
Appendix B (i) (1) (A)	Tables which identify laws, regulations, ordinances, standards, adopted local, regional, state, and federal land use plans, leases, and permits applicable to the proposed project, and a discussion of the applicability of, and conformance with each. The table or matrix shall explicitly reference pages in the application wherein conformance, with each law or standard during both construction and operation of the facility is discussed; and	Sections 5.1 – 5.16, Section 4, Section 7, Appendix B		
Appendix B (i) (1) (B)	Tables which identify each agency with jurisdiction to issue applicable permits, leases, and approvals or to enforce identified laws, regulations, standards, and adopted local, regional, state and federal land use plans, and agencies which would have permit approval or enforcement authority, but for the exclusive authority of the commission to certify sites and related facilities.	Sections 5.1 – 5.16, Section 4, Section 7		
Appendix B (i) (2)	The name, title, phone number, address (required), and email address (if known), of an official who was contacted within each agency, and also provide the name of the official who will serve as a contact person for Commission staff.	Sections 5.1 – 5.16, Section 4, Section 7		

Adequacy Issue: Adequate ____ Inadequate ____

DATA ADEQUACY WORKSHEET

Revision No. 0 Date ____

Technical Area: **Reliability** Project: ____ Technical Staff: ____

Project Manager: ____ Docket: ____ Technical Senior: ____

Siting Regulations	**Information**	**AFC Page Number and Section Number**	**Adequate Yes or No**	**Information Required To Make AFC Conform With Regulations**
Appendix B (i) (3)	A schedule indicating when permits outside the authority of the commission will be obtained and the steps the applicant has taken or plans to take to obtain such permits.	Sections 5.1 – 5.16, Section 4, Section 7		